Final Technical Report
for the
JEA Large-Scale CFB Combustion Demonstration Project

Submitted to
U.S. DEPARTMENT OF ENERGY
National Energy Technology Laboratory (NETL)
Pittsburgh, Pennsylvania 15236
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JEA

Building Community

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1.0 OVERVIEW

JEA is the largest public power company in Florida and the eighth largest public power company in the US, and is currently serving over 360,000 customers. Prior to the JEA Large-Scale CFB Demonstration Project, JEA's Northside Generating Station (NGS) consisted of three oil/gas-fired steam electric generating units. NS Units 1 and 2 were each nominally rated at 275 megawatts (MW) and Unit 3 at 518 MW. Units 1 and 3 had been in service since 1966 and 1977 respectively. Unit 2 was completed in 1972, but had been inoperable since about 1983 due to major boiler problems.

As part of its Integrated Resource Planning Study in 1996, JEA concluded that additional base load capacity was needed to support Jacksonville's growing need for energy. The optimum source for that additional capacity was repowering NS Unit 2 with a nominal 300 MW state-of-the-art atmospheric circulating fluidized bed (CFB) boiler fueled by coal and/or petroleum coke. In order to provide the project with an overall environmental benefit, increase the economies of scale, and further diversify JEA's overall fuel mix, a decision was made to repower NS Unit 1 with an identical CFB boiler as well. The environmental benefits included a reduction in emissions of nitrogen oxides, sulfur oxides and particulate matter by at least 10% compared to 1994/95 levels while increasing the net plant capacity by 250%.

In early 1997, detailed Condition Assessments of Unit 1 and Unit 2 Balance of Plant (BOP) equipment and systems were conducted by JEA and Black & Veatch (B&V). The results of these assessments indicated that both Unit 1 and Unit 2 were good candidates for repowering and capable of operating for an additional twenty years, provided various equipment and system upgrades were made.

In April 1997, JEA's Board approved the project and authorized staff to proceed with contract negotiations and environmental permitting. Contract negotiations were subsequently initiated with Foster Wheeler (FW) and the United States Department of Energy (DOE) for participation in cost sharing for the first unit (Unit 2) as a Large-Scale CFB Combustion Demonstration Project. Cooperative Agreement DE-FC21-90MC27403 between JEA and the DOE was finalized in September 1997. The Agreement provided for cost sharing based on a total approved project budget of $305,773,774. This represented a DOE cost share of $73,072,464, with the remainder of the project cost paid by JEA.

Environmental permitting work was initiated by FW Environmental in the latter part of 1997. The permitting work, and associated preliminary engineering, proceeded through 1998, and early 1999. FW began detailed engineering for the Boiler Island, including the Air Quality Control System (AQCS), Chimney, and Limestone Preparation System, in December 1998. B&V began detailed engineering for BOP systems, including the Fuel Handling System, in February 1999. Permits necessary to begin construction were issued in July 1999 with site clearing and construction beginning in August 1999.

Initial synchronization of Unit 2 occurred on February 19, 2002, and initial synchronization of Unit 1 occurred on May 29, 2002.

The purpose of this report is to provide a technical account of the total work performed for the project under the Cooperative Agreement between JEA and the DOE. Although the DOE participation was only in the Unit 2 and Common Facilities portion of the project, the project execution by JEA included design and construction for repowering of Unit 1 in the same time frame. Thus, while this report is primarily for Unit 2 and Common Facilities, it also contains some summary type information for the entire Unit 1 and 2 Repowering Project.

1.1 Awards and Reports

The Northside Repowering Project received the 2002 Powerplant Award from Power magazine. In addition, during design and construction, a number of papers were presented on the JEA Large-Scale CFB Demonstration Project at various conferences.

The Cooperative Agreement between DOE and JEA stipulated that a number of reports be prepared to document and summarize various aspects of the Demonstration Project. Following is a listing of the reports that were developed:

Title
Detailed Public Design Report
Start-up Modifications Report
Topical Report 22: The JEA Large-Scale CFB Combustion Demonstration Project
Topical Report: Air Quality Control System
Topical Report: Ash Processing System
Fuel Capability Demonstration Test Report 1: 100% Pittsburgh 8 Coal Fuel
Fuel Capability Demonstration Test Report 2: 50/50 Blend Petroleum Coke and Pittsburgh 8 Coal Fuel
Fuel Capability Demonstration Test Report 3: 100% Illinois 6 Coal Fuel
Fuel Capability Demonstration Test Report 4: 80/20 Blend Petroleum Coke and Pittsburgh 8 Coal Fuel
Final Technical Report (this report)

The above reports are available on the DOE Clean Coal Technology Compendium website at the following link:

http://www.netl.doe.gov/cctc/resources/library/bibliography/demonstration/aepg/baepgfb_jackea.html

1.2 Abbreviations

Following is a definition of abbreviations used in this report. Generally, at their first use, these terms are fully defined in the text of the report, followed by the abbreviation in the parenthesis. Subsequent references typically use the abbreviation only.

Abbreviation	Definition
AQCS	Air Quality Control System
B&V	Black & Veatch Corporation
BOP	Balance of Plant
BSA	Byproduct Storage Area
Btu	British Thermal Unit

Abbreviation	Definition
$CaCO_3$	wt. fraction $CaCO_3$ in limestone
CAE	Clean Air Engineering
CaO	Lime
Ca:S	Calcium to Sulfur Ratio
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CY	Calendar Year
DAF	Dry, ash free
DAHS	Data Acquisition Handling System
DCS	Distributed Control System
DOE	Department of Energy
EAF	Equivalent Availability Factor
F	Fluorine or Degrees Fahrenheit
FF	Fabric Filter
FGS	Fluor Global Services
FW	Foster Wheeler
FWEC	Foster Wheeler Energy Corporation
FWUSA	Foster Wheeler USA
GAG	Gross Actual Generation
GCF	Gross Capacity Factor
GE	General Electric
GOF	Gross Output Factor
GPD	Gallons per Day

Abbreviation	**Definition**
gpm	gallons per minute
HF	Fluoride
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
HRA	Heat Recovery Area
ID	Induced Draft
IP	Intermediate Pressure
lb	Pounds
lb/hr	Pounds per hour
lb/MMBtu	pounds per million Btu
lb/TBtu	pounds per trillion Btu
LP	Low Pressure
MCR	Maximum Continuous Rating
MFT	Master Fuel Trip
$MgCO_3$	wt. fraction $MgCO_3$ in limestone
MgO	Magnesium Oxide
MMBtu	Million Btu
MW	Megawatts
MWh	Megawatt-hour
NCF	Net Capacity Factor
NERC	North American Electric Reliability Council
NGS	Northside Generating Station
NH_3	Ammonia
NOF	Net Operating Factor

Abbreviation	Definition
NO_x	Oxides of Nitrogen
NS	Northside
O&M	Operations and Maintenance
PA	Primary Air
Pb	Lead
PGT	Power Generation Technologies
PI	Plant Information
Pitt 8	Pittsburgh 8
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
ppm	parts per million
ppmdv	Pounds per million, dry volume
psia	Pounds per square inch pressure absolute
psig	pounds per square inch pressure gauge
PTC	Power Test Code
SA	Secondary Air
SDA	Spray Dryer Absorber
SH	Service Hours
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
TG	Turbine Generator
tph	tons per hour
TWIP	Turbine Water Induction Prevention
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Carbon

Abbreviation	Definition
WAPC	Wheelabrator Air Pollution Control
WWGay	W.W. Gay Mechanical Contractor
ZCC	Zachry Construction Corp.

2.0 PROJECT HISTORY

2.1 Background

In September 1997, the U.S. DOE and JEA entered into an agreement to repower JEA's Northside Generating Station Unit 2 with CFB boiler technology from FW. The purpose of this agreement was to demonstrate CFB technology for coal firing in large-scale applications while providing increased plant electric output, reduced emissions and broad fuel flexibility.

CFB technology is an advanced method for utilizing coal and other solid fuels in an environmentally acceptable manner. The low combustion temperature allows sulfur dioxide (SO_2) capture via limestone injection while minimizing oxides of nitrogen (NO_x) emissions. The technology is flexible enough to handle a wide range of coals as well as petroleum coke and blends of coal and coke. CFB boilers have been installed in smaller, industrial-size plants but have only recently been considered for larger utility power plants. The DOE helped test a 110 MW CFB boiler at a power station in Colorado in one of its earliest and most successful Clean Coal Technology projects. At nearly 300 MW each, the JEA CFB boilers more than double the size of the Colorado unit and are among the world's largest.

The JEA Large-Scale CFB Demonstration Project involved repowering Northside (NS) Unit 2, an existing 275 MW oil/gas fired boiler which had been out of service since the early 80's, with a 297.5 MW CFB boiler. The DOE contributed approximately $73 million from the Clean Coal Technology Program, and JEA provided the remainder of the total budget. The DOE cost sharing included two years of demonstration test runs, during which both coal and coal/petroleum coke blends were fired. JEA also repowered Northside Unit 1 with an identical CFB boiler. The DOE did not cost share in the Unit 1 repowering.

2.2 Project Organizational Structure

JEA contracted with FW to supply the extended boiler island scope of the project. Foster Wheeler Energy Corporation (FWEC) provided the design and supply of the CFB boilers. Foster Wheeler USA (FWUSA) provided engineering, procurement, and construction management services on a cost reimbursable basis for installation of the boilers and for furnishing and erecting the air pollution control systems, chimney, limestone preparation system, and ash handling systems. Foster Wheeler Environmental Corporation, a subsidiary of FWUSA, provided environmental permitting services.

The remaining portions of the project were implemented by JEA staff and supplemented by B&V through a pre-existing Alliance with JEA for engineering services. Procurement, construction and related services were provided through other pre-existing Alliances between JEA and Zachry Construction Corporation (ZCC), Fluor Global Services (FGS), W.W. Gay Mechanical Contractor, Inc.(WWGay), and Williams Industrial Services Inc. This work included upgrades of the existing turbine island equipment, construction of the receiving and handling facilities for the fuel and reagent required for solid fuel firing, upgrading of the electrical switchyard facilities, and construction of an ash management system.

2.3 Project Scope

The project involved the construction and operation of two CFB boilers fueled by coal and petroleum coke to repower two existing steam turbines, each generating nearly 300 MW. CFB boilers are generally capable of removing over 98% of SO_2. However, to improve the overall economics and environmental performance, a polishing scrubber was included to minimize reagent consumption while firing petroleum coke containing up to 8.0% sulfur. The relatively low furnace operating temperature of about 1600° F inherently results in appreciably lower NO_x emissions compared to conventional coal-fired power plants. However, the project also included a new selective non-catalytic reduction (SNCR) system to further reduce emissions of NO_x. Over 99.8% of particulate emissions are removed by a baghouse.

In addition to the CFB combustor and the air pollution control systems, new equipment for the project included a chimney as well as fuel, limestone, and ash handling systems. The project also required overhaul and/or upgrades of existing systems such as the steam turbines, condensate and feedwater systems, circulating water systems, water treatment systems, plant electrical distribution systems, the switchyard, and the plant control systems.

New construction associated with the Repowering Project occupies approximately seventy-five acres of land at the Northside Generating Station (see the Site Arrangement Drawing and Overall Plot Plan in Appendix A). Solid fuel delivery to the site required new receiving, handling, and storage facilities. Limestone and ash storage and handling facilities were also required. Wherever possible, existing facilities and infrastructure were used for the project. These include the intake and discharge system for cooling water, the wastewater treatment system, and the electric transmission lines and towers.

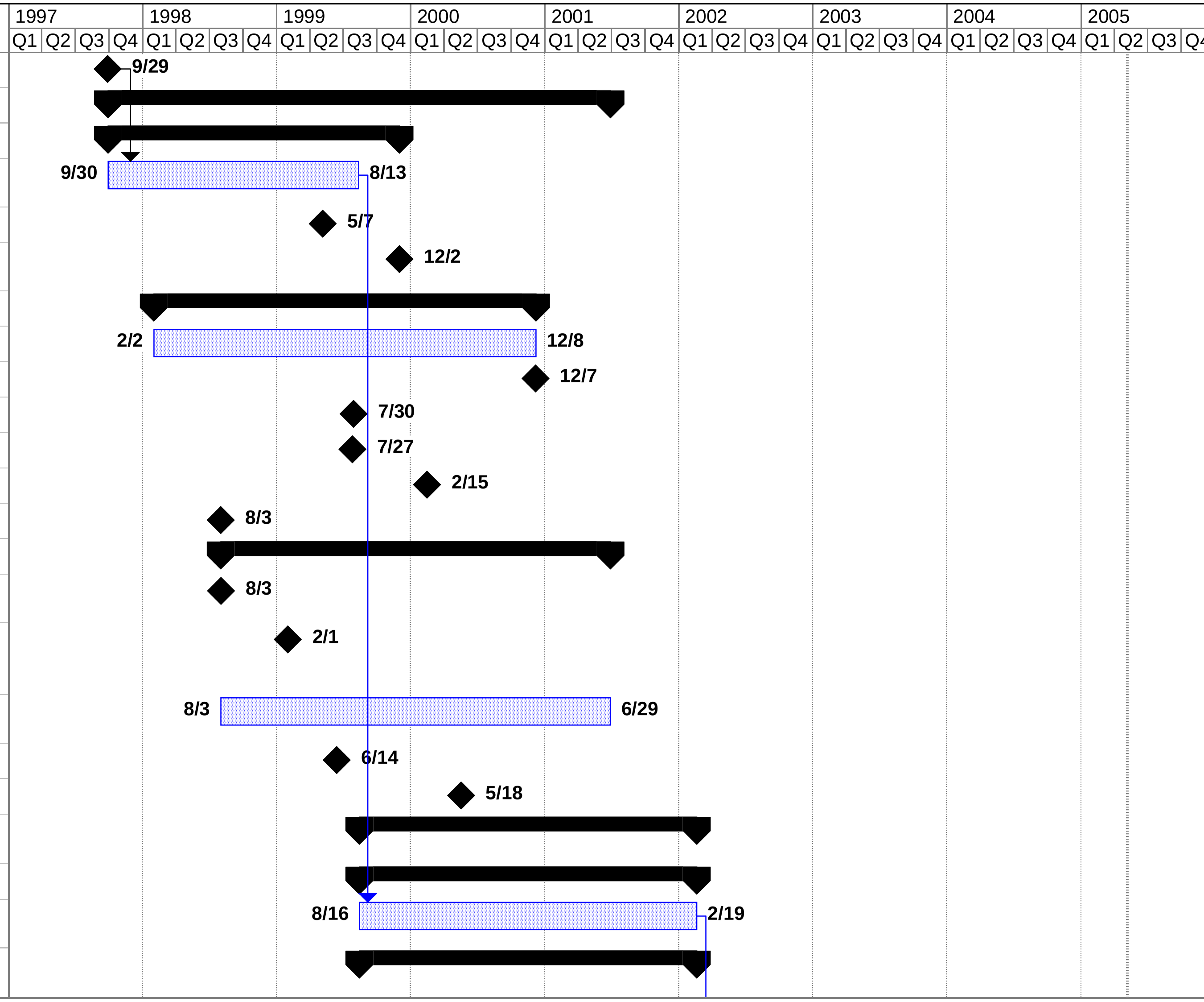
Project activities included engineering and design, permitting, equipment procurement, construction, start-up, and demonstration of the commercial feasibility of the technology. During the demonstration period, Unit 2 was operated under normal dispatch conditions and also tested on several different types of coal and coal/petroleum coke blends to demonstrate the viability of the technology. Units 1 and 2 continue to operate successfully to provide a significant portion of JEA's power generation.

2.4 Summary Project Schedule

The Summary Project Schedule on the following pages illustrates the major project activities and milestones for the JEA Large-Scale CFB Combustion Demonstration Project, from the signing of the Cooperative Agreement between DOE and JEA in September 1997 through the conclusion of this DOE Demonstration Project.

JEA Northside Unit 2 Repowering
Summary Project Schedule

ID	Task Name
1	Cooperative Agreement Signed
2	**DOE Phase 1 - Design**
3	**Project Management**
4	Project Management - Phase 1
5	Project Management Plan
6	Environmental Monitoring Plan
7	**Permitting**
8	Overall Permitting Activities
9	NEPA Completion
10	FACE Water Permit
11	ERP Permit
12	NPDES Water Permit
13	**Preliminary Design Complete**
14	**Design Engineering**
15	NTP - Boiler/AQCS Engineering
16	NTP - Balance of Plant & Material Handling Engineering
17	Detailed Design Engineering
18	40% Design Review
19	90% Design Review
20	**DOE Phase 2 - Construction and Start-up**
21	**Project Management**
22	Project Management - Phase 2
23	**Unit 2 Construction and Start-up**



Project: NS Repowering DOE Sched
Date: Thu 5/5/05

Task	Rolled Up Task	External Tasks
Progress	Rolled Up Milestone	Project Summary
Milestone	Rolled Up Progress	Group By Summary
Summary	Split	

JEA Northside Unit 2 Repowering
Summary Project Schedule

ID	Task Name	Dates (1997–2005)
24	NTP - Boiler Construction	8/16
25	Construction Activities	8/16 – 2/19
26	Drum Lift	6/5
27	50% Construction Review	1/25
28	Boiler Hydro	5/23
29	100% Construction Review	8/14
30	First Fire - Solid Fuel	2/14
31	Initial Syncronization	2/19
32	**DOE Phase 3 - Operation**	
33	**Project Management**	
34	Project Management - Phase 3	2/20 – 3/31
35	Public Design Report	9/19
36	Environmental Monitoring/Test Plan	2/24
37	Start-up Modifications Report	5/4
38	**Fuel Flexibility Testing**	
39	Test Protocol	3/1
40	Test Report 1 - 100% Pittsburgh 8 Coal	9/3
41	Test Report 2 - 50/50 Blend Pitt 8 Coal and Pet Coke	12/3
42	Test Report 3 - 100% Illinois 6 Coal	2/7
43	Test Report 4 - 80/20 Blend Pet Coke and Pitt 8 Coal	2/18
44	**Final Technical Report**	3/31

Project: NS Repowering DOE Sched
Date: Thu 5/5/05

Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary

3.0 PROJECT TECHNICAL OVERVIEW

The CFB boiler technology selected by JEA for the Demonstration Project is an advanced method for utilizing coal and other solid fuels in an environmentally acceptable manner. The low combustion temperature allows SO_2 capture via limestone injection, while minimizing NO_x emissions. The technology provides the capability to burn a wide range of fuels including coal, petroleum coke, and blends of the two.

Although CFB boilers are generally capable of removing over 98% of SO_2, a polishing scrubber was included to minimize reagent consumption and improve environmental performance while firing petroleum coke containing up to 8.0% sulfur. Based on the incremental amount of SO_2 removal required, dry scrubber technology, followed by a baghouse for particulate removal, was selected for the AQCS.

Firing of solid fuels on the Northside site required the design and installation of a completely new system for receiving, handling, and storing coal and petroleum coke. The same system is used for receiving and handling limestone for CFB boiler reagent.

Firing of solid fuels results in the production of ash byproducts, so new provisions had to be designed and installed for handling and processing these materials. Facilities were also included for storing the byproducts pending development of useful markets for these materials.

A detailed condition assessment of existing systems and components was conducted during the conceptual design stage of the project. Based on that report, existing systems and components were either reused, upgraded, or replaced.

Detailed System Descriptions of the major boiler, turbine, and balance of plant systems are contained in the Detailed Public Design Report for this project, which is available on the DOE website at the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/JEAmaster.pdf

3.1 Circulating Fluidized Bed (CFB) Boilers

The need to improve the fluidized bed combustion efficiency (which also increases overall boiler efficiency and reduces operating costs) and the desire to burn a much wider range of fuels has led to the development and application of the CFB boiler. Through the years, boiler suppliers have been increasing the size of these high-efficiency steam generators. See Fig. 3-1 for the Northside CFB Process Layout.

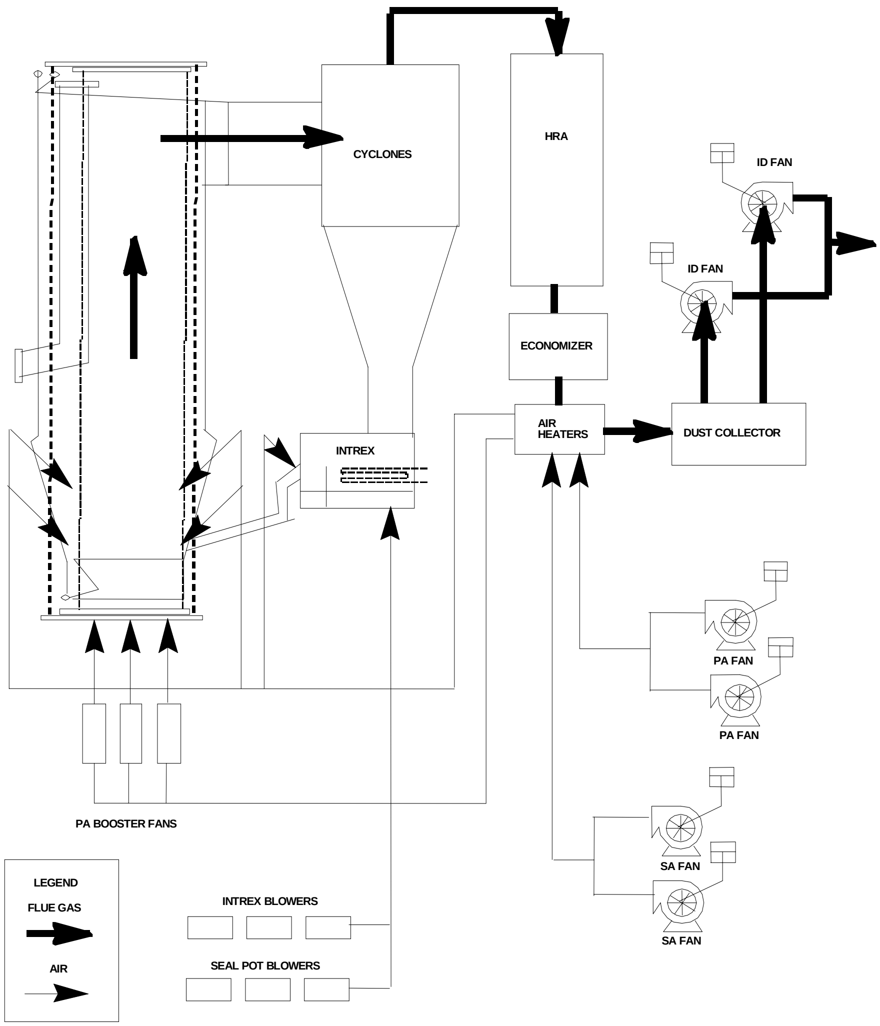


FIGURE 3-1 NORTHSIDE CFB PROCESS LAYOUT

HRA = Heat Recovery Area
PA = Primary Air
ID = Induced Draft
SA = Secondary Air

The CFB process offers the means for efficiently burning a wide variety of fuels while maintaining low emissions. Fuel is fed to the lower furnace where it is burned in an upward flow of combustion air. Fuel, ash, and unburned fuel carried out of the furnace are collected by a separator and returned to the lower furnace. Limestone, which is used as a sulfur sorbent, is also fed to the lower furnace. Furnace temperature is maintained in the range of 1500° to 1700° F by suitable heat absorbing surface. This process offers the following advantages:

Fuel Flexibility – The relatively low furnace temperatures are below the ash softening temperature for nearly all fuels. As a result, the furnace design is independent of ash characteristics, which allows a given furnace to handle a wide range of fuels.

Low SO_2 Emissions – Limestone is an effective sulfur sorbent in the temperature range of 1500° to 1700° F. SO_2 removal efficiency of 95% and higher has been demonstrated in the industry along with good sorbent utilization.

Low NO_X Emissions – Low furnace temperatures of 1500° to 1700° F plus staging of air feed to the furnace produces very low NO_X emissions.

High Combustion Efficiency – The long solids residence time in the furnace resulting from the collection/recirculation of solids via the cyclone, plus the vigorous solids/gas contact in the furnace caused by the fluidization airflow, results in high combustion efficiency, even with difficult-to-burn fuels. The unburned carbon loss component of the combustion efficiency is typically in the 1% to 2% range. For the JEA Northside boilers, the predicted unburned carbon loss was 2% on coal and 1.25% on petroleum coke.

3.2 Northside CFB Boilers Design Parameters

The design parameters at maximum continuous rating (MCR) for the Northside CFB Boilers are indicated in Table 3-1.

TABLE 3-1 BOILER DESIGN PARAMETERS

Parameter	100% MCR
Main Steam Flow	1,994,000 lb/hr
Main Steam Pressure at Superheater Outlet Header	2620 psig
Main Steam Pressure at Turbine	2,500 psig
Main Steam Temperature	1006° F
Reheat Steam Flow	1,773,000 lb/hr
Reheat Steam Pressure	555 psig
Reheat Steam Temperature	1006° F
Boiler Efficiency firing Performance Coal	88.1%
Boiler Efficiency firing Performance Petroleum Coke	90%

The performance fuel specifications for coal and petroleum coke, including ranges, are indicated in the following Table 3-2.

Boiler Arrangement Drawings are included in Appendix A.

TABLE 3-2 FUEL SPECIFICATIONS

Delayed Petroleum Coke				Performance Range	
	Minimum	Maximum	Performance	Minimum	Maximum
Heat Content, Btu/lb (HHV)	13,000	na	14,000	13,900	na
Hardgrove Grindability	25	80	wr	wr	wr
As received Particle Size (inches)	0	4	na	na	na
Proximate Analysis					
Volatile Matter	7.0	14.0	9.0	7.0	11.0
Fixed Carbon	71.0	88.0	81.6	na	na
Moisture	na	15.0 (Note 7)	9.0	na	15.0
Ash	na	3.0	0.4	na	3.0
Ultimate Analysis					
Carbon	78.0	89.0	79.0	79.0	85.0
Hydrogen	3.2	5.8	3.6	3.25	4.17
Nitrogen	0.4	2.0	1.0	.73	1.6
Oxygen	0.1	1.8	0.3	0.3	1.65
Sulfur	3.0	8.0	6.7	4.0	8.0
Moisture	na	15.0 (Note 7)	9.0	na	15.0
Ash	na	3.0	0.4	na	3.0
Vanadium, ppm	na	3,500 (Note 8)	na	na	na
Nickel, ppm	na	600 (Note 8)	na	na	na
Fluoride	na	(Note 5)	na	na	na
Lead	na	(Note 5)	na	na	na
Mercury	na	(Note 5)	na	na	na
Chlorine	na	(Note 10)	na	na	na
Alkalis	na	(Note 9)	na	na	na

Coal	Performance			Performance Range	
	(Note 11)			Minimum	Maximum
Heat Content, Btu/lb (HHV)	12,690			11,600	13,959
Hardgrove Grindability	na			na	na
As received Particle Size (inches)	na			na	na
Ash Fusion (reducing, soft, °F)	na			na	na
Volatile Matter (% DAF)	43.41			39.1	47.0
Proximate Analysis					
Volatile Matter	35.63			na	(Note 4)
Fixed Carbon	46.4			na	na
Moisture	5.2 (Note 8)			na	12.0
Ash (Note 3)	12.8			7.0	15.0

Coal (continued)	Performance			Performance Range	
	(Note 11)			Minimum	Maximum
Ultimate Analysis					
Carbon	68.6			66.6	70.6
Hydrogen	4.6			4.0	5.2
Nitrogen	1.3			0.8	1.6
Oxygen	4.11			3.98	4.2
Chlorine	0.09			na	0.1
Sulfur (Note 3)	3.3			2.97	3.6
Moisture	5.2 (Note 7)			na	12.0
Ash (Note 3)	12.8			7.0	15.0
Fluoride	na			na	na
Lead	na			na	na
Mercury	na			na	na
Mineral Analysis of Coal Ash					
Phosphorous Pentoxide	wr			wr	wr
Silicon Oxide	wr			wr	wr
Ferric Oxide	wr			wr	wr
Aluminum Oxide	wr			wr	wr
Titanium Oxide	wr			wr	wr
Calcium Oxide	wr			wr	wr
Magnesium Oxide	wr			wr	wr
Sulfur Trioxide	wr			wr	wr
Potassium Oxide	wr			wr	wr
Sodium Oxide	wr			wr	wr
Coal	85% MCR Range			100% MCR Range	
	Minimum	Maximum		Minimum	Maximum
Heat Content, Btu/lb (HHV)	10,000	na		11,600	na
Hardgrove Grindability	35	80		35	80
As received Particle Size (inches)	0	4		0	4
Ash Fusion (reducing, soft, °F)	2,050	2,680		2,050	2,680
Volatile Matter (% DAF)	na	47.0		na	47.0
Proximate Analysis					
Volatile Matter	20.0	40.0 (Note 4)		30	36
Fixed Carbon	37.0	na		42	na
Moisture	na	15.0 (Note 7)		Na	13.0 (Note 7)
Ash (Note 3)	7.0	15.0		7.0	15.0
Ultimate Analysis					
Carbon	49.3	86.0		59	72
Hydrogen	3.2	6.0		3.9	5.3
Nitrogen	0.4	1.9		0.8	1.6

Coal (continued)	85% MCR Range			100% MCR Range	
	Minimum	Maximum		Minimum	Maximum
Oxygen	3.0	9.8		3.0	9.8
Chlorine	na	0.3 (Note 10)		na	0.3 (Note 10)
Sulfur (Note 3)	0.5	4.5		0.5	4.5
Moisture	na	15.0 (Note 7)		na	13.0 (Note 7)
Ash (Note 3)	7.0	15.0		7.0	15.0
Fluoride	na	(Note 5)		na	(Note 5)
Lead	na	(Note 5)		na	(Note 5)
Mercury	na	(Note 5)		na	(Note 5)
Mineral Analysis of Coal Ash					
Phosphorous Pentoxide	0.04	3.0		0.04	3.0
Silicon Oxide	30.0	65.0		30.0	65.0
Ferric Oxide	2.9	45.0		2.9	45
Aluminum Oxide	18.0	36.0		18.0	36.0
Titanium Oxide	0.3	3.0		0.3	3.0
Calcium Oxide	0.5	9.0		0.5	9.0
Magnesium Oxide	0.1	2.0		0.1	2.0
Sulfur Trioxide	0.1	8.0		0.1	8.0
Potassium Oxide	0.1	4.0 (Note 9)		0.1	4.0 (Note 9)
Sodium Oxide	0.1	2.0 (Note 9)		0.1	2.0 (Note 9)

Note:

1. na = no limit applicable
2. All data is for fuel “as received”, and is percent by weight unless otherwise noted.
3. Coal minimum sulfur content is 0.5% given at least 12.0% ash. Coal minimum ash content is 7.0%, given at least 1.0% sulfur. For coals with sulfur content between 0.5% and 1.0%, and ash content between 7% and 12%, the minimum coal ash content as a function of sulfur content shall be as shown in Fig. 3-5.
4. The maximum coal volatile matter is 47% on a dry-ash free basis.
5. The emissions guarantee shall be based upon uncontrolled emissions as resulting from the combined inputs from fuel and limestone that do not exceed the following values:
   Lead - 0.00278 lb/MBtu (HHV)
   Mercury - 0.0000174 lb/MBtu (HHV)
   Fluorine (as HF) - 0.0106 lb/MBtu (HHV)
6. wr = within range
7. Surface moisture of the crushed fuel should be below 10% to avoid conveying and feeding hang-ups.
8. The total vanadium and nickel content in the fuel should not exceed 2,000 ppm. Operation at higher levels than 2,000 ppm will result in increased outages for unit cleaning and repairs.
9. The fuels fired in the boiler should have a combined acetic acid soluble sodium (Na) and potassium (K) content less than 0.05% (500 ppm) on a dry fuel basis to prevent bed sintering and agglomeration.
10. The chlorine level in the fuel should be less than 0.1% on a dry fuel basis to avoid corrosion and agglomeration problems.
11. Performance coal will be Eastern US coal.

3.3 Limestone Preparation System

The limestone preparation system grinds and dries raw limestone and pneumatically transports it to the limestone storage silo for each unit. The limestone preparation system is designed for grinding limestone at a maximum feed size of 1 inch to a product size of -2000 microns meeting the CFB desired product distribution curve, with a residual moisture content of 1% maximum.

Three pneumatic transfer systems, one for each unit, and a shared spare system, are provided to convey the prepared limestone from the preparation building to the unit's silo. Each system is capable of transferring limestone to either Unit 1 or 2.

3.4 Air Quality Control System (AQCS)

To optimize overall plant performance, a polishing SO_2 scrubber was included in the design. The CFB boiler provides approximately 90% SO_2 capture via limestone injection, with the remaining capture from a semi-dry polishing scrubber via injection of lime. Overall SO_2 capture is over 98%.

Although CFB boilers can achieve 98% SO_2 removal, limestone utilization is reduced as removal efficiencies exceed 90% to 95%. The polishing scrubber allows reduction of the overall sorbent use, such that the savings in operating cost (sorbent, ash disposal) offset the capital and operating costs of the polishing scrubber. Another consideration in the decision to add the scrubber was the enhanced environmental performance regarding reductions of trace element emissions provided by the scrubber.

The polishing scrubber is a spray dryer/baghouse combination. The spray dryer utilizes a dual fluid nozzle atomized with air, and the baghouse is a pulse-jet design. A key feature of the polishing scrubber is a recycle system which adds fly ash to the reagent feed, thus utilizing the unreacted lime in the fly ash from the CFB boiler and reducing the amount of fresh lime required.

The polishing scrubber for each unit, provided by Wheelabrator Air Pollution Control (WAPC), consists of a Spray Dryer Absorber/Fabric Filter (SDA/FF) Dry Scrubbing System to control SO_2 and acid gases, solid particulates, and heavy metals. Each system consists of:

- A Two Fluid Nozzle Spray Dryer Absorber (SDA)
- A Medium-Pressure Pulse Jet Fabric Filter (FF)
- A Feed Slurry Preparation System
- A common Absorbent Preparation System for both units, consisting of a Lime Storage Silo, redundant Vertical Ball Mill Slaking Systems, and redundant Transfer/Storage Tanks and pumps.
- A common Air Compressor System to provide atomizing air for the SDA, dried pulse air for the FF, and instrument air. The compressors are provided with a closed loop cooling system. Waste heat from the compressor is used to preheat the reuse water feed to the SDA Feed Slurry System.

3.5 Turbine Generator and Balance of Plant Systems

The Unit 2 Turbine Generator (TG) was upgraded to maximize output and improve turbine heat rate as much as practical. The high pressure/intermediate pressure (HP/IP) rotor, diaphragms, and inner casing were replaced with a General Electric (GE) Dense Pack design, which added four stages to the turbine, and increased turbine efficiency. The normal operating throttle pressure was also increased from 2400 psig to 2500 psig. In addition, the original mechanical linkage type turbine control system was replaced with a state-of-the-art Mark VI electrohydraulic control system, to allow better response to load changes and for complete integrated control, protection, and monitoring of the turbine generator and accessories. A new brushless excitation system was also installed on the generator, and a new turbine lube-oil conditioner was installed.

Unit 2 was originally designed to provide power to the JEA grid at 138kV. However, to better interface with present and future grid capabilities, the output from Unit 2 was increased to 230 kV. This required replacement of the generator step-up transformer and associated substation upgrades.

The once-through circulating water system was upgraded by replacing the original 90% copper/10% nickel heat-transfer surfaces in the condenser damaged by erosion/corrosion with modular bundles consisting of titanium tubes welded to solid titanium tubesheets. The existing circulating water pumps were replaced with larger capacity pumps. The traveling screens were replaced with those that have man-made basket material to increase their life. Debris filters were added to minimize condenser tube pluggage and possible damage. A sodium hypochlorite shock-treatment system was installed to prevent sea life from adhering to the titanium components of the condenser.

Upgrades to the condensate system in Unit 2 included upgrades to the condensate pumps and condensate booster pumps, replacement of the steam packing exhausters, replacement of the low pressure (LP) feedwater heaters, including replacement of the tube bundle in the lowest pressure heater (located in the condenser neck), replacement of the deaerator and storage tank, installation of a new condensate polisher, and installation of new chemical feed systems. The new feedwater heaters included Type 304 N stainless steel tubes (welded to tubesheets), instead of the aluminum brass tubes rolled into the tubesheets of the original heaters.

Upgrades to the feedwater system in Unit 2 included replacement of the HP feedwater heaters, upgrades to the boiler feed pumps and fluid drives, and replacement of the boiler feed pump drive motor. Again, the new feedwater heaters included Type 304 N stainless steel tubes (welded to tubesheets), instead of the aluminum brass tubes rolled into the tubesheets of the original heaters.

The capability of existing piping systems and components in Unit 2 was reviewed to confirm adequacy for the new operating and design conditions. If necessary, these systems and components were upgraded or replaced. Existing 2-½ inch and larger valves in Unit 2 were either refurbished or replaced. Nearly all 2 inch and smaller piping and valves in Unit 2 were replaced. Essentially all instrumentation in Unit 2 was replaced.

The original control systems in Unit 2 were replaced with a new distributed control system (DCS) provided by ABB Inc, to provide control, monitoring, and protection of the boiler, turbine interfaces, and balance of plant systems. FW provided the logic design for the CFB boiler, and B&V provided the logic design for the BOP systems, including provisions for turbine water induction prevention (TWIP). ABB provided the programming to implement the logic design for the boiler and BOP systems.

The Unit 2 auxiliary electric system (switchgear and motor control centers) was replaced because of equipment obsolescence. All power and control wiring was replaced due to the age of the wiring and because the existing control wiring was not segregated from the power wiring, thus not meeting the requirements of the new DCS system.

Other miscellaneous enhancements included the installation of additional air dryers and screw-type air compressors and the installation of titanium plate-type heat exchangers for the Unit 2 closed cooling water system, similar to those previously installed in Unit 1.

3.6 Fuel Handling System (Coal, Petroleum Coke, and Limestone)

The function of the Fuel Handling System is to receive coal, petroleum coke, and limestone from "Panamax" vessels (maximum vessel size which can pass through the Panama Canal) and to convey it to stock-out and storage areas. From there coal and petroleum coke are reclaimed and conveyed to the in-plant fuel silos; limestone is reclaimed and conveyed to the Limestone Preparation System.

The major components of the Fuel Handling System are as follows:

- Continuous Ship Unloader
- Belt Conveyors and Support Structures
- Domes
- Radial Stacker/Reclaimers
- Traveling Trippers
- Belt Feeders
- Belt Scales
- Magnetic Separators
- Metal Detectors
- Gates and Chutework
- Dust Suppression and Dust Collection Systems
- Screw Conveyors
- Vacuum Cleaning Systems
- Hoppers
- Telescopic Chute

3.7 Ash Handling

The ash handling system transports bed ash from the outlets of the stripper coolers to the bed ash silos. It also transports fly ash from the economizer and air heater hoppers, as well as the baghouse hoppers, to the fly ash silos. Two sets of ash handling systems and associated equipment are provided, one for Unit 1 and the other for Unit 2.

3.8 Reuse Water

Reuse water is domestic wastewater that has been treated and disinfected to a high degree and is reused for beneficial purposes. The reuse water used at NGS is treated wastewater from the District II Water Reclamation Facility. The wastewater is treated through primary, secondary and advanced treatment. During primary treatment, large solids are removed from the wastewater. Secondary treatment uses microorganisms to remove the remaining solids and organic material from the wastewater. After secondary treatment, the wastewater travels through cloth membrane filters, with a pore size of approximately 10 microns, to remove virtually all remaining solids. During advanced or final treatment, the wastewater is disinfected using chlorine or ultraviolet light to destroy bacteria, viruses and other pathogens.

Consumption of reuse water at NGS is nearly 1 million gallons per day when all three units are operating. The reuse water is used for circulating water pump seals, boiler/precipitation area drains, polishing scrubbers, ash slurry preparation, and fuel handling dust suppression and wash down. Future uses may include irrigation.

3.9 Ash Processing and Storage

Two bed ash silos and two fly ash silos provide for short term (approximately three days) surge capacity and storage of bed ash and fly ash. The bed ash and fly ash from the silos is slurried using reuse water. The bed ash slurry and fly ash slurry are then blended together and pumped to the Byproduct Storage Area (BSA) using positive displacement GEHO pumps.

Ash in the BSA sets up to form a low strength aggregate type material, with essentially the only water run-off being precipitation which falls in the area. This aggregate material is suitable for use as fill material for road construction or other applications where fill material is needed. JEA has received an approval letter from FDEP characterizing their CFB byproduct (bed ash and fly ash) as an "industrial byproduct" and allowing it to be used for beneficial purposes such as civil applications and stabilization processes for remedial projects. JEA is actively marketing and selling this material in Florida and Georgia, with the intent of transporting all ash generated to off site locations for beneficial uses.

4.0 START-UP

FW was responsible for the commissioning and start-up of the boiler and AQCS systems, and ZCC was responsible for the commissioning and start-up of BOP systems. The JEA Start-up Group was responsible for the overall coordination of plant start-up, as well as commissioning and start-up of the Material Handling Systems (coal, petroleum coke, and limestone), and of the turbine/generator and related auxiliary systems. JEA Operations was responsible for operation of completed and integrated systems after turnover of the various systems for normal operation.

Detailed design activities for the project were essentially complete by July 2001. FW began on-site staffing for the commissioning and start-up activities for the FW scope of work for the project in the latter part of 2000. Pre-boiler chemical cleaning of the Unit 2 condensate and feedwater systems (excluding boiler systems) was completed in early June 2001. Chemical cleaning of the Unit 2 boiler was completed in September 2001. First fire of Unit 2 on gas occurred on December 1, 2001, and Unit 2 steam blows were completed on January 15, 2002. Initial synchronization of Unit 2 occurred on February 19, 2002, and full load operation (on coal) was achieved and sustained on May 5, 2002.

4.1 Modifications During Start-up and Initial Operation

As indicated above, the detailed design activities for the project were essentially complete by July 2001, but some design changes and scope additions were made during the latter stages of construction and start-up. Many of these changes were issued due to scope increases or changes requested by JEA, field conditions that differed from the design basis (due to missing or incorrect vendor data, incorrect field data, etc), drawing errors, etc. Other changes were identified and implemented during start-up and initial operation of various integrated systems and initial operation of Unit 2 by JEA.

After August 2002, JEA initiated a number of modifications and changes that could be implemented quickly, with little or no down time, to improve the operation of the Unit 2 boiler and AQCS systems. Many of these modifications were implemented during the Fall 2002 planned outage. In addition, JEA developed a more comprehensive list of design modifications and changes which could be completed during a scheduled outage in the Spring of 2003, to optimize performance of Unit 2 during the summer peak period. These modifications are referred to as Phase I Completion Modifications.

A detailed description of the Unit 2 Start-up, and of the modifications made during start-up and initial operation, can be found in the Start-up Modifications Report for this project, which is available on the DOE website at the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/Start-Up%20Modifications%20Report_final.pdf

5.0 OPERATIONS AND MAINTENANCE

Prior to the Repowering Project, Units 1 and 3 fired relatively high cost liquid fuels and natural gas (Unit 2 was not operating). As a result, capacity factor of these units was limited due to economic dispatching practices by JEA. Since Units 1 and Unit 2 have been repowered, they have fired relatively low cost solid fuels (Unit 3 continues to fire liquid fuels and natural gas). As a result, the combined power production of the three units has increased significantly, and at the same time, total plant emissions have been reduced.

Significant changes in operations and maintenance (O&M) practices were required by the change of Units 1 and 2 from oil and gas fired boilers to solid fueled boilers, with associated AQCS and ash handling systems. During start-up and testing of the units, JEA dedicated significant efforts and costs to development of O&M procedures and to training of O&M personnel for the new equipment and systems.

5.1 Unit 2 Operations Summary

From the time of initial synchronization on February 19, 2002, Unit 2 was in combined start-up, testing, and operational mode of service through the summer of 2002. Initial operation of the boiler on coal and higher ratios of coal/pet coke blends were successful. However, attempts at operation on 100% pet coke resulted in agglomeration of ash in the INTREX's and cyclones within a week or so of operation, requiring a forced outage to remove the ash build-up. As a result, blending of pet coke and coal was required for reliable operation of the boiler. Initially, the ratio was limited to a maximum of 70% pet coke, but this was increased to 80% pet coke after the 2002 summer peak season. Other significant problems encountered with the boiler operation included limestone drying and feed problems, stripper cooler pluggages, expansion joint failures, and back-sifting into the PA plenum. Problems were also encountered with density control and spray quality in the AQCS system. The issues with limestone feed resulted in an operational practice of overfeeding limestone to the boiler in order to preclude excursions of SO_2 emissions from the stack. This resulted in doing most of the SO_2 removal in the boiler.

A summary of key annual operating and availability data for Unit 2 for calendar year (CY) 2003 and 2004, is provided in Table 5-1.

TABLE 5-1 ANNUAL OPERATING AND AVAILABILITY DATA

Parameter	CY 2003	CY 2004	Remarks
Gross MWH's Generated	1,791,221	1,459,351	NERC: Gross Actual Generation (GAG)
Net MWH's	1,673,981	1,357,427	
Heat Rate, B/kWh	9,514	9,518	
Starts	15	9	Excludes Attempted Starts
Hours on Line	6,843	5,450	NERC: Service Hours (SH)
Load Factor (Gross)	88.0%	90.0%	NERC: Gross Output Factor (GOF)
Net Output Factor (NOF), %	87.2%	89.3%	
Capacity Factor (Gross)	68.7%	55.8%	NERC: Gross Capacity Factor (GCF)
Net Capacity Factor (NCF), %	68.2%	55.6%	
Equivalent Availability Factor (EAF)	72.8%	58.7%	

A monthly summary of Unit 2 operating data during 2003, and 2004 is provided in Appendix C.

For purposes of comparison to the Northside Unit 2 operating data above, Table 5-2 below presents the industry average operating and availability data for coal plants in the United States of capacity between 200 MW and 399 MW, based on data for calendar years 1999 through 2003, as reported in the North American Electric Reliability Council (NERC) Generating Availability Report. While the coal plants of this size in the NERC data base are primarily pulverized coal units with scrubbers, a comparison to Northside Unit 2 (also solid fuel fired with scrubbers) is considered to be indicative, but not directly comparable. It should also be noted that these statistics are from units that have been operating for many years and have worked through startup and early operational issues to achieve a stable O&M mode. This process has not yet been completed on Unit 2. One single issue with a large impact on performance is the failure of superheater tubes.

During the time frame of August 2003 through May 2004, the boiler experienced a series of outages due to superheater tube failures (see Section 5.2 below). A detailed discussion of technical issues surrounding these failures can be found in Section 6.1. This single issue resulted in a loss of about 464,100 MWh's of generation during CY 2003 and 2004. If these tube failures had not occurred, the average EAF during CY 2003 and 2004 would have been nearly 75%, as indicated in the Table 5-2.

TABLE 5-2 COMPARISONS TO NERC DATA

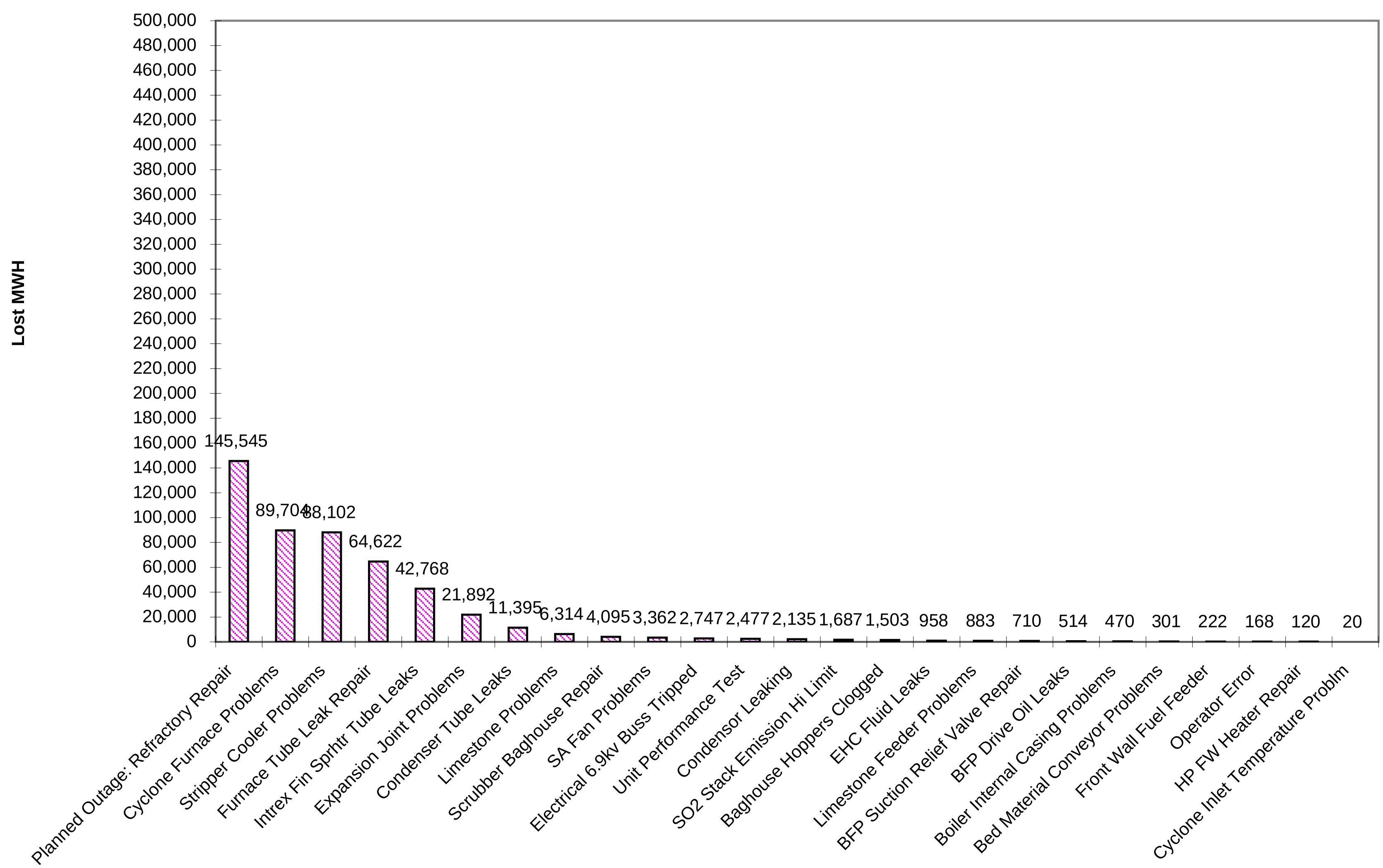
Parameter	200 to 399 MW Unit Size (1)	NS Unit 2 Averages for CY 2003 and 2004	Northside Unit 2 Averages without SH Tube Failures CY 2003 and 2004
Average Dependable Capacity (Gross), MW	299.5	297.5	297.5
Average Actual Unit Starts per Year	14.73	12	10 (estimated)
Average Service Hours per Year	7,434	6,146.5	
Average Service Factor, SF, %	84.85	78.2	
Average Net Output Factor, NOF, %	81.21	88.3	
Average EAF, %	84.01	65.8	74.7

1. Based on North American Electric Reliability Council, Generating Availability Data System, for coal fired steam units, 1999 thru 2003.

A graphical representation of Unit 2 lost generation hours during 2003 and 2004 by NERC cause code is provided on the following pages.

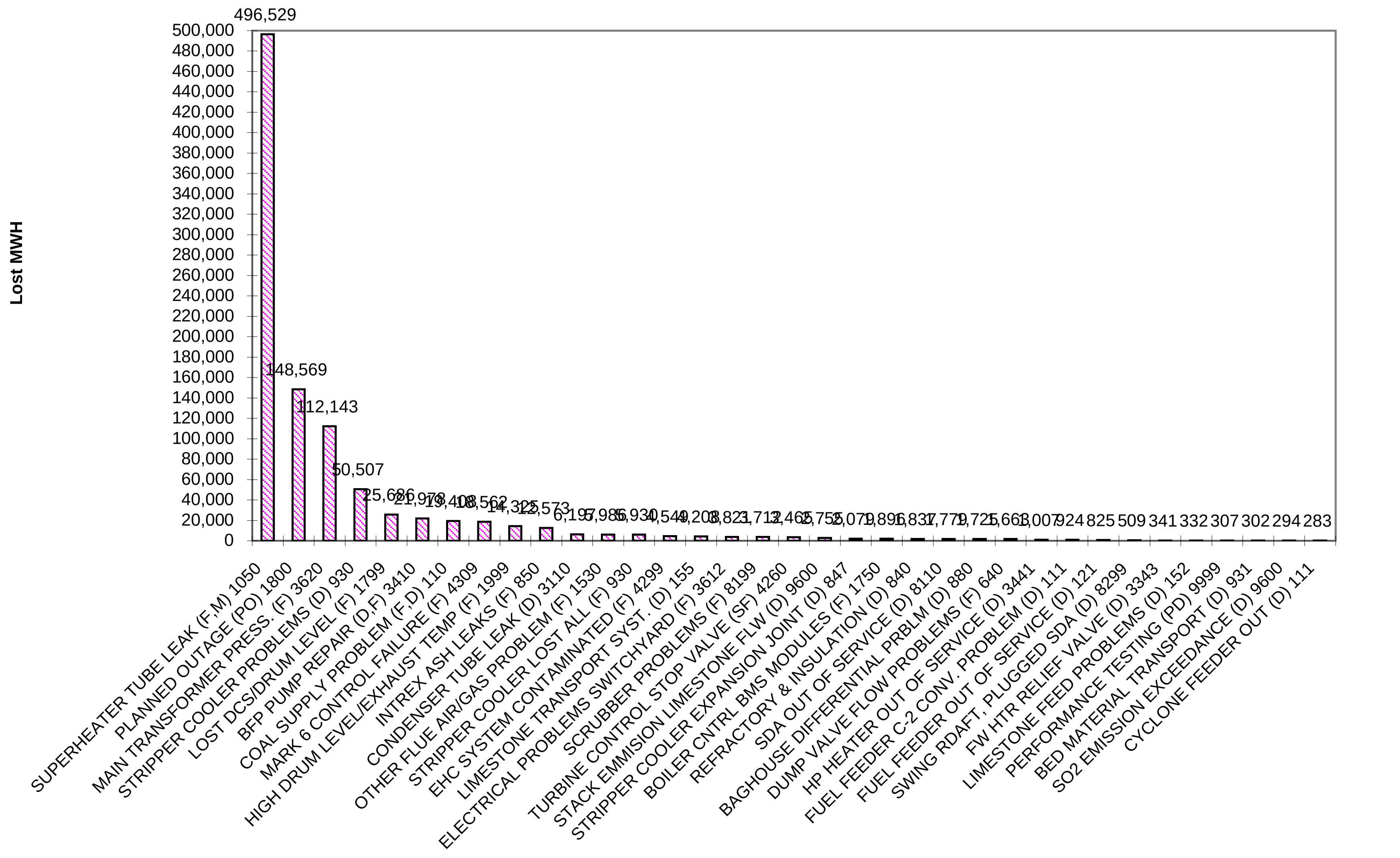
NS2 Lost MWH by Cause for FY03

(GADS Data)



NS2 Lost MWH by Cause for FY04

(GADS Data)



5.1.1 Water and Wastewater Flows. A water mass balance diagram for the Northside Plant site (Units 1, 2, and 3) is included in Appendix A. A summary of actual average daily flows for some of the key flow streams, based on available monthly flow data for CY 2003, and 2004, is shown in Table 5-3. Applicable permit limits are also indicated.

TABLE 5-3 AVERAGE DAILY WATER FLOWS

	Average Daily Flow, Gallons per Day (GPD) X 1000				
Flow Stream	**Water Balance***		**CY 2003**	**CY 2004**	**Permit Limit**
Surface Water	827,000 (827,000)		782,173	763,770	827,000
Ground Water	517.6 (1,283.7)		530.4	590.9	571.0
Reuse Water	853.9 (2,299.6)		809.6**	991.9**	928.8
CWTS Influent	431.6 (1,744.7)		497.8	601.3	
Perc Ponds to District II	0.0 (250.0)		126.8	132.1	
	* Flows in parenthesis are 24 hour maximum flows.				
	** Excludes December 2003 through April 2004 due to broken reuse water pipeline.				

Monthly water and wastewater flow rates for the Northside site are indicated with the operating data in Appendix C.

5.1.2 Stack Emissions. Stack emissions data for Unit 2 is collected and reported by the Continuous Emissions Monitoring System (CEMS). Table 5-4 below provides a summary of Unit 2 stack emissions data during 2003 and 2004.

TABLE 5-4 STACK EMISSIONS DATA

Parameter	CY 2003	CY 2004	Permit Limits
SO2 Emissions, Tons	1,131.8	1,095.6	
SO2 Emissions, lb/MMBtu	0.14	0.17	0.20 (24 hr average)
NOx Emissions, Tons	525.5	492.6	
NOx Emissions, lb/MMbtu	0.07	0.08	0.09 (30 day average)
Particulate Matter, Tons	41.23	29.72	
Particulate Matter, lb/MMbtu	0.005	0.005	
CO, Tons	297.3	290.6	
CO, lb/MMbtu	0.04	0.04	
CO, lb/hr	84	100	350 (24 hr average)
VOC, Tons	11.92	11.63	
VOC, lb/MMbtu	0.001	0.002	
VOC, lb/hr	3.4	4.0	

Monthly stack emissions data for Unit 2 is included with the operating data in Appendix C.

5.1.3 Ash Production. Total bed ash and fly ash production rates for Units 1 and 2 combined are as follows, along with an estimate of the portion of the bed ash and fly ash from Unit 2.

TABLE 5-5 ASH PRODUCTION RATES

Parameter	CY 2003	CY 2004
Total Bed Ash, Tons	312,400	195,439
Total Fly Ash, Tons	179,700	153,623
Unit 2 Bed Ash, Tons	153,236	96,515
Unit 2 Fly Ash, Tons	88,145	75,865
Byproduct Sales	0	38,312

Note that some byproduct sales were made in 2004, primarily into Georgia. In late 2004, JEA received an approval letter from FDEP characterizing their CFB byproduct (bed ash and fly ash) as an "industrial byproduct" and allowing it to be used for beneficial purposes such as civil applications and stabilization processes for remedial projects. All byproduct generated is expected to be sold, and the originally planned Cell 2 of the BSA is not being developed.

5.2 Unit 2 Maintenance Summary

The level of maintenance required on Unit 2, particularly the boiler, has been relatively high, due to the ash agglomeration problems, limestone feed problems, stripper cooler pluggages, expansion joint failures, and back-sifting into the PA plenum mentioned above. Table 5-6 provides a list of Unit 2 outages of significant duration, through December 2004, which have been required to address many of these problems.

TABLE 5-6 MAJOR UNIT 2 OUTAGES

Outage Start Date	Outage End Date	Duration, Days	Primary Purpose of Outage
April 16, 2002	April 30, 2002	14	MFT, Removal of excessive ash build-up
May 31, 2002	June 14, 2002	14	Tube Leak Repairs
July 7, 2002	July 19, 2002	12	Bed Excursion in Boiler
July 27, 2002	August 9, 2002	12	Remove Pluggage in Cyclone
October 22, 2002	November 17, 2002	26	Planned Outage for Boiler Modifications
December 21, 2002	January 8, 2003	19	Stripper Cooler Problems
January 28, 2003	February 6, 2003	9	Furnace Wall Tube Repairs
April 1, 2003	April 23, 2003	21	Planned Outage for Boiler Refractory Modifications and Repairs
August 19, 2003	September 8, 2003	20	Cyclone problems, Intrex tube leaks

Outage Start Date	Outage End Date	Duration, Days	Primary Purpose of Outage
November 3, 2003	November 25, 2003	22	Boiler Inspection
February 11, 2004	March 4, 2004	22	Superheater Tube Leaks (Intrex)
March 8, 2004	March 19, 2004	11	Superheater Tube Leaks (Intrex)
March 30, 2004	April 5, 2004	6	Superheater Tube Leaks (Intrex)
May 1, 2004	May 7, 2004	6	Superheater Tube Leaks (Intrex)
June 19, 2004	July 6, 2004	17	Change-out of Generator Step-up Transformer
October 26, 2004	November 29, 2004	32	Planned Outage for Boiler Modifications

In addition, there were numerous other load reductions and short unit outages in the above time frame. Note that the monthly Equivalent Availability Factors (EAF's) for 2003 and 2004 listed in the Operating Data in Appendix C include all unit outages and load reductions.

5.3 O&M Staffing

O&M of the three units at the Northside site is handled by a single organization within JEA, which in many cases shares or rotates duties and responsibilities between units. The total O&M staff presently consists of a total of 251 persons for the three units. Units 1 and 2 are each a nominal 300 MW CFB pet coke/coal fired unit, and Unit 3 is a 530 MW heavy oil fired unit.

5.4 O&M Costs

During the first two years of operation, Unit 2 encountered significant operating problems (primarily boiler related) and associated forced outages which resulted in high maintenance and repair costs and a low EAF, as described above. As a result, the annual O&M costs for Unit 2, particularly on a per MWh basis, were extremely high during the demonstration period, and are not considered to be representative of future O&M costs for the unit. Refer to Section 6.0 for a description of boiler design modifications and upgrades that have been, or are being, implemented to improve boiler reliability and operation.

6.0 MODIFICATIONS AND UPGRADES (PHASE II)

In addition to the Phase I Completion Modifications made during the Spring 2003 outage on Unit 2, JEA has also implemented, or is considering implementing, a number of additional major modifications, referred to as Phase II completion modifications. The intent of these modifications is to further improve the reliability, maintainability, and performance of Unit 2. These modifications include the following:

- Intrex Design Modifications
- Expansion Joint Modifications
- Stripper Cooler Modifications
- Limestone Silo and Feed System Modifications
- Limestone Preparation System Modifications

The following paragraphs provide a description of the problems encountered and the modifications being considered to resolve these problems.

6.1 Intrex Design Modifications

The intrex is the part of the boiler that contains both the loop seal and the intermediate and finishing superheater surface. The boiler has three intrex boxes, two with intermediate superheat surface and one with finishing superheat surface. There are both mechanical and operational issues with the design of the intrex. The mechanical issues consist of superheater tube support failure and in-service cracking of superheater tubes. The operational issues consist of agglomeration of the hot loop material within the intrex and backing up of material into the cyclone.

The superheater tube failures are attributed to a combination of the design of the tube bundle support system coupled with lack of solution annealing of the tube bends. The primary failure is radial cracking of the superheater tube bend at the weld. The problem is found to be the worst in the finishing superheater where the steam temperatures are the highest, and is most prevalent on the bend where the large bundle support lug is installed. The large lug acted as a heat exchange fin and caused the operating temperature of the particular tube bend to be higher than the rest of the bundle, which accelerated the failure.

An investigation revealed that at the time of design ASME code did not require solution annealing of the bends for the stresses that were calculated to exist in the bundle. Following the manufacture of these elements the code was changed, and if manufactured today the tube bends would have to be solution annealed.

As a temporary measure all of the finishing superheater bends were replaced with solution annealed bends without the large support lug. The support system was re-designed to include only a sliding pad. At the same time the temporary repair was being performed a design was done and material was ordered to install replacement finishing superheater tube bundles. The design called for 50% of the surface area to be replaced, with the balance being eliminated due to installation considerations. The replacement bundles were installed in the fall 04 planned outages and have provided satisfactory performance.

The operational issues with the intrex boxes include agglomeration of hot loop material within the boxes while burning high percentages of petroleum coke. This has resulted in pluggage of the boiler cyclone with agglomerated hot loop material. The failure mechanism appears to be agglomeration of the material under conditions of poor fluidization. To mitigate the problem without major modifications it is necessary to burn at least 20% coal with the petroleum coke to reduce the tendency of the hot loop material to agglomerate.

JEA is currently evaluating long-term modifications that will mitigate both the agglomeration and tube failure issues. These modifications are expected to be implemented within the next five years.

6.2 Expansion Joint Modifications

JEA has experienced failures of the hot loop expansion joints, including the cyclone inlet, cyclone outlet and intrex return leg expansion joints. Minor design modifications have been successfully performed to reduce forced outages due to these expansion joints. It is expected that further modifications will be performed associated with the intrex modifications noted above.

6.3 Stripper Cooler Modifications

Bed ash is removed from the boiler through stripper coolers which are designed to remove carbon from the ash and cool the ash. JEA has experienced both mechanical and operational issues with the stripper coolers. The stripper coolers are mounted to the boiler steel and close-coupled to the boiler through a sliding expansion joint. There have been numerous failures and high O&M cost associated with these expansion joints. Modifications have been performed to reduce the forced outages and derates associated with these joints, but further improvements are desired. Operationally, the coolers are not able to operate at design capacity and forced derates sometimes occur due to pluggage or inadequate flow. A considerable amount of O&M is spent attempting to unplug or restart flow through stripper coolers. JEA is currently evaluating a range of changes from modification of the existing coolers all the way through replacement with an alternate design.

6.4 Limestone Silo and Feed System Modifications

The original limestone feed system from the bottom of the limestone silos near the boilers for Northside Units 1 and 2 were prone to “rat-holing” and/or bridging, interrupting the flow of limestone to the boilers. Frequent manual rodding of the limestone in the silo and lower hoppers was required to restore the flow of limestone, particularly when the limestone moisture content was high. To eliminate the limestone feed interruptions, Jenike & Johanson (J&J), a company specializing in the design on bulk material handling systems, designed and furnished system modifications to replace the lower conical portion of each limestone silo with a mass flow hopper bottom. In addition, the rotary feed type valves were replaced with hopper outlet slide gate valves, mass flow screw feeders, diverter valves and stainless steel pipe chutes to the inlets of existing rotary air lock valves. On-site construction work was performed by one of the JEA Alliance Contractors during the Fall 2004 outages on Units 1 and 2. Although limestone feed issues have not been eliminated, performance has improved significantly. It is believed that most remaining issues are related to moisture in the finished limestone.

6.5 Limestone Preparation System Modifications

The limestone preparation system that was supplied was not able to meet the design drying capacity or the design sizing curve. An ongoing program is underway to improve limestone drying and reduce the amount of fines produced by the preparation process. Improvements have been made, and JEA is continuing to perform tests to optimize the process. The final resolution is not yet known.

7.0 PERFORMANCE TESTING

7.1 INTRODUCTION

The Cooperative Agreement between the DOE and JEA required JEA to demonstrate fuel flexibility of the unit to utilize a variety of different fuels, specifically Pittsburgh 8 coal, Illinois 6 coal, and two blends of Pittsburgh 8 coal with petroleum coke. Therefore, four fuel flexibility demonstration tests were conducted during 2004 to document the ability of the unit to utilize a variety of fuels and fuel blends in a cost effective and environmentally responsible manner. Fuel flexibility was quantified by measuring the following parameters:

- Boiler efficiency
- CFB boiler sulfur capture
- AQCS sulfur and particulate capture
- The following flue gas emissions
    - Particulate matter (PM)
    - Oxides of nitrogen (NO_x)
    - Sulfur dioxide (SO_2)
    - Carbon monoxide (CO)
    - Carbon dioxide (CO_2)
    - Ammonia (NH_3)
    - Lead (Pb)
    - Mercury (Hg)
    - Fluorine (F)
    - Dioxin
    - Furan
- Stack opacity

Note that the term "unit" refers to the combination of the CFB boiler and the AQCS. The AQCS consists of a lime-based SDA and a PJFF

7.2 Test Protocol

The tests were conducted in accordance with an approved Fuel Capability Demonstration Test Protocol, which can be accessed on the DOE website at the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/FCTP.pdf

7.3 Test Schedule

The four fuel capability demonstration tests were conducted on the following dates:

- Test 1 100% Pittsburgh 8 coal January 13 through 16, 2004
- Test 2 50/50 Blend Pitt 8 Coal and Pet Coke January 27 through 31, 2004
- Test 3 Illinois 6 Coal June 7 through 9, 2004
- Test 4 80/20 Blend Pet Coke and Pitt 8 Coal August 10 through 13, 2004

7.4 Summary of Test Results

7.4.1 Valve Line-Up Requirements

With the exception of isolating the blow down systems, drain and vent systems, and the soot blower system, the boiler was operated normally in the coordinated control mode throughout the boiler efficiency test period. Prior to the start of each testing period, a walk down was conducted to confirm the 'closed' position of certain main steam and feedwater system valves.

7.4.2 Test Reports

A detailed test report was prepared to document the results of each test. Each report includes commentary on the test results as well as limited part load performance data. These detailed reports can be accessed on the DOE website at the following link:

http://www.netl.doe.gov/cctc/resources/library/bibliography/demonstration/aepg/baepgfb_jackea.html

7.4.3 Full Load Test Results

The results of the 100% load tests are summarized in Tables 7-1 through 7-4 on the following pages. The design MCR values indicated are the original design values provided by FW. Corrections to MCR conditions were made in accordance with Section 6.2.1 of the Fuel Capability Demonstration Test Protocol.

TABLE 7-1 - 100% PITTBURGH 8 FUEL TESTS RESULTS
100% LOAD

Parameter	Design Maximum-Continuous Rating (MCR)	January 13, 2004 Test (**corrected to MCR, see Note 4)	January 14, 2004 Test (**corrected to MCR, see Note 4)
Boiler Efficiency (percent)	88.1	90.6** (Note 1)	90.6** (Note 1)
Capacity Calculation (percent)	NA	97.14	94.55
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,999,572**	2,000,369**
Pressure (psig)	2,500	2,400	2400
Temperature (°F)	1,000	997**	996.6**
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,820,447	1,769,377
Pressure (psig)	547.7	570.9	568.7
Temperature (°F)	1,000	1008.1**	1008.25**
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,819,973	1,768,905
Pressure (psig)	608.6	570.5	568.24
Enthalpy (Btu/lb)	1,304.5	1297.3	1,297.3
Feedwater to Economizer			
Temperature (°F)	487.5	484.5	484.1
Pittsburgh 8 Coal Constituents (As-Received)			
Carbon %	68.6	72.7	72.3
Hydrogen %	4.6	4.84	4.7
Sulfur %	3.3	4.84	4.56
Nitrogen %	1.3	1.37	1.35
Chlorine %	0.09	0.18	0.14
Oxygen %	4.11	2.11	2.54
Ash %	12.8	6.89	7.06
Moisture %	5.2	7.26	7.39
HHV (Btu/lb)	12,690	12,877	12,970
Fuel Flow Rate (lb/hr)	NA	207,558	206,906
Limestone Composition (% By Weight)			
CaCO3	92.0	90.86	91.81
MgCO3	3.0	3.31	2.95
Inerts	4.0	5.34	4.9
Total Moisture	1.0	0.49	0.34

Parameter	Design Maximum-Continuous Rating (MCR)	January 13, 2004 Test (**corrected to MCR, see Note 4)	January 14, 2004 Test (**corrected to MCR, see Note 4)
AQCS Lime Slurry Composition (% By Weight)			
CaO	85.0	45.15	46.02
MgO and inerts	15.0	54.85	53.98
AQCS Lime Slurry Density – % Solids	35	5.57	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	57,600	54,625
Flue Gas Emissions			
Nitrogen Oxides, NO_x, lb/MMBtu (HHV)	0.09	0.074	0.081
Uncontrolled SO_2, lb/MMBtu (HHV)	5.20	7.52	7.03
Boiler Outlet SO_2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2371	.2902
Stack SO_2 lb/MMBtu, (HHV)	0.15	0.102	0.106
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.004	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.026	0.027
Opacity, percent	10	1.1	1.0
Ammonia (NH_3) Slip, ppmvd	2.0	1.17	
Ammonia feed rate, gal/hr	NA	7.16	8.38
Lead, lb/MMBtu	2.60×10^{-5} (max)	3.516×10^{-7}	
Mercury (fuel and limestone)	NA	8.24×10^{-6}	
Mercury, lb/MMBtu (at stack)	1.05×10^{-5} (max)	7.238×10^{-6} (see Note 2)	
Total Mercury Removal Efficiency, percent	No requirement	14.0	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	$< 3.09 \times 10^{-5}$	
Dioxins / Furans	No Limit	6.52×10^{-14}	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from FW data).
NOTE 2: Refer to Section 4.3.4.1 of Test Report 1 for description of mercury testing anomaly.
NOTE 3: Design boiler outlet SO_2 emission rate based on 85% removal of SO_2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of the FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.

TABLE 7-2 - 50/50 BLEND PITT 8 COAL AND PET COKE TEST RESULTS
100% LOAD

Parameter	**Design Maximum-Continuous Rating (MCR)**	**January 27, 2004 Test (**corrected to MCR, see Note 4)**	**January 28, 2004 Test (**corrected to MCR, see Note 4)**
Boiler Efficiency (percent)	88.1 (Coal) 90.0 (Pet Coke)	91.6 **(Note 1)	91.7 **(Note 1)
Capacity Calculation (percent)	NA	95.3	95.4
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,848,031**	1,846,341**
Pressure (psig)	2,500	2,401	2,401
Temperature (°F)	1,000	1,002**	1,001**
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,776,860	1,776,167
Pressure (psig)	547.7	569.1	565.4
Temperature (°F)	1,000	1,007**	1,008**
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,775,434	1,774,004
Pressure (psig)	608.6	568.4	564.9
Enthalpy (Btu/lb)	1,304.5	1,295.25	1,292.91
Feedwater to Economizer			
Temperature (°F)	487.5	484.3	483.5
50/50 Blend Fuel Analysis (As-Received)			
Carbon %	73.8	74.45	73.68
Hydrogen %	4.1	4.4	4.6
Sulfur %	5.0	5.34	5.86
Nitrogen %	1.15	1.47	1.63
Chlorine %	0.05	0.09	0.11
Oxygen %	2.20	1.25	1.26
Ash %	6.6	5.75	5.91
Moisture %	7.1	7.34	7.05
HHV (Btu/lb)	13,345	13,429	13,251
Fuel Flow Rate (lb/hr)	NA	194,172	195,177
Limestone Composition (% By Weight)			
CaCO3	92.0	91.4	86.4
MgCO3	3.0	2.95	2.82
Inerts	4.0	5.15	10.43
Total Moisture	1.0	0.51	0.36

Parameter	**Design Maximum-Continuous Rating (MCR)**	**January 27, 2004 Test (**corrected to MCR, see Note 4)**	**January 28, 2004 Test (**corrected to MCR, see Note 4)**
AQCS Lime Slurry Composition (% By Weight)			
CaO	85.0	46.77	47.03
MgO and inerts	15.0	53.23	52.97
AQCS Lime Slurry Density – % Solids	35	5.23	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	66,434	73,001
Flue Gas Emissions			
Nitrogen Oxides, NO_x, lb/MMBtu (HHV)	0.09	0.07	0.07
Uncontrolled SO_2, lb/MMBtu (HHV) - based on 50/50 blend	7.49	7.95	8.845
Boiler Outlet SO_2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2026	0.2771
Stack SO_2 lb/MMBtu, (HHV)	0.15	0.093	0.11
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.0041	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.015	0.016
Opacity, percent	10	1.01	1.80
Ammonia (NH_3) Slip, ppmvd	2.0	0.325	
Ammonia feed rate, gal/hr	NA	3.73	6.26
Lead, lb/MMBtu	2.60×10^{-5} (max)	8.22×10^{-7}	
Mercury (fuel and limestone), µg/g	NA	3.02×10^{-7}	
Mercury, lb/TBtu (at stack)	10.5 (max)	< 8.532 (see Note 2)	
Total Mercury Removal Efficiency, percent	No requirement	Not Utilized	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	1.69×10^{-5}	
Dioxins / Furans	No Limit	NOT TESTED	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from FW data).
NOTE 2: Refer to Section 4.3.4.1 of Test Report 2 for description of mercury testing anomaly.
NOTE 3: Design boiler outlet SO_2 emission rate based on 85% removal of SO_2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of the FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.

TABLE 7-3 - ILLINOIS 6 COAL TEST RESULTS
100% LOAD

Parameter	Design Maximum-Continuous Rating (MCR)	June 8, 2004 Test (**corrected to MCR, see Note 4)	June 9, 2004 Test (**corrected to MCR, see Note 4)
Boiler Efficiency (percent)	88.1 (Pittsburgh 8 Coal)	88.3 (Note 1)	88.0 (Note 1)
Capacity Calculation (percent)	NA	101.5	100.0
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,974,013	1,926,677
Pressure (psig)	2,500	2,400	2,400
Temperature (°F)	1,000	998	999
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,897,211	1,859,959
Pressure (psig)	547.7	571.5	573.0
Temperature (°F)	1,000	1,005	1,011
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,897,091	1,851,738
Pressure (psig)	608.6	570.9	572.3
Enthalpy (Btu/lb)	1,304.5	1,293.6	1,285.6
Feedwater to Economizer			
Temperature (°F)	487.5	484.1	484.6
Illinois 6 Fuel Analysis (As-Received)			
Carbon %	64.48	64.93	64.70
Hydrogen %	4.40	4.31	4.57
Sulfur %	2.71	3.17	3.32
Nitrogen %	1.24	1.27	1.26
Chlorine %	0.15	0.15	0.15
Oxygen %	7.34	7.14	7.37
Ash %	8.57	7.08	6.59
Moisture %	11.11	12.10	12.19
HHV (Btu/lb)	11,603	11,649	11,664
Fuel Flow Rate (lb/hr)	NA	232,730	232,535
Limestone Composition (% By Weight)			
CaCO3	92.0	96.6	96.77
MgCO3	3.0	1.3	1.39
Inerts	4.0	2.1	1.84
Total Moisture	1.0	0.16	0.22

Parameter	**Design Maximum-Continuous Rating (MCR)**	**June 8, 2004 Test (**corrected to MCR, see Note 4)**	**June 9, 2004 Test (**corrected to MCR, see Note 4)**
AQCS Lime Slurry Composition (% By Weight)			
CaO (See Note 5)	85.0	46.24	46.24
MgO and inerts (See Note 5)	15.0	53.76	53.76
AQCS Lime Slurry Density – % Solids	35	5.23	
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	64,005	73,001
Flue Gas Emissions			
Nitrogen Oxides, NO_x, lb/MMBtu (HHV)	0.09	0.086	0.103
Uncontrolled SO_2, lb/MMBtu (HHV)	7.49	5.44	5.69
Boiler Outlet SO_2, lb/MMBtu (HHV) [See Note 3]	0.78	0.2763	0.2887
Stack SO_2 lb/MMBtu, (HHV)	0.15	0.107	0.08
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.0019	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.0198	0.024
Opacity, percent	10	1.5	1.0
Ammonia (NH_3) Slip, ppmvd	2.0	< 0.5206	
Ammonia feed rate, gal/hr	NA	5.53	6.76
Lead, lb/MMBtu	2.60×10^{-5} (max)	$< 4.352 \times 10^{-7}$	
Mercury (fuel), µg/g	NA	0.50	
Mercury, lb/TBtu (at stack)	10.5 (max)	0.345	
Total Mercury Removal Efficiency, percent	No requirement	95 (see Note 2)	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	$< 4.582 \times 10^{-5}$	
Dioxins / Furans	No Limit	NOT TESTED	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from FW data).
NOTE 2: Refer to Section 4.3.4.1 of Test Report 3 for basis.
NOTE 3: Design boiler outlet SO_2 emission rate based on 85% removal of SO_2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of the FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.
NOTE 5: These components were not captured for this test - average results from Test #1 and Test #2 are indicated.

TABLE 7-4 - 80/20 BLEND PET COKE AND PITT 8 COAL TEST RESULTS
100% LOAD

Parameter	Design Maximum-Continuous Rating (MCR)	August 10, 2004 Test (**corrected to MCR, see Note 4)	August 11, 2004 Test (**corrected to MCR, see Note 4)
Boiler Efficiency (percent)	88.1 (Coal) 90.0 (Pet Coke)	91.52 ** (Note 1)	91.62 ** (Note 1)
Capacity Calculation (percent)	NA	95.6	96.05
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,901,483 **	1,910,388 **
Pressure (psig)	2,500	2,401	2,401
Temperature (°F)	1,000	914.5 **	912.4 **
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,715,491	1,723,401
Pressure (psig)	547.7	592.6	590.8
Temperature (°F)	1,000	1,001.4 **	1,000.8 **
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,715,448	1,723,361
Pressure (psig)	608.6	593.5	591.6
Enthalpy (Btu/lb)	1,304.5	1,290.1	1,289.97
Feedwater to Economizer			
Temperature (°F)	487.5	420.0	419.9
80/20 Blend Fuel Analysis (As-Received)			
Carbon %	73.8	81.36	82.14
Hydrogen %	4.1	3.63	3.67
Sulfur %	5.0	3.7	3.74
Nitrogen %	1.15	1.93	1.95
Chlorine %	0.05	0.03	0.03
Oxygen %	2.20	1.72	0.89
Ash %	6.6	2.33	2.41
Moisture %	7.1	5.34	5.20
HHV (Btu/lb)	13,345	14,085	14,081
Fuel Flow Rate (lb/hr)	NA	186,885	186,982
Limestone Composition (% By Weight)			
CaCO3	92.0	97.55	97.23
MgCO3	3.0	1.18	1.16
Inerts	4.0	1.27	1.61
Total Moisture	1.0	0.3	0.29

Parameter	**Design Maximum-Continuous Rating (MCR)**	**August 10, 2004 Test (**corrected to MCR, see Note 4)**	**August 11, 2004 Test (**corrected to MCR, see Note 4)**
AQCS Lime Slurry Composition (% By Weight)			
CaO (See Note 5)	85.0	46.24	46.24
MgO and inerts (See Note 5)	15.0	53.76	53.76
AQCS Lime Slurry Density – % Solids	35	1.25	1.41
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	50,892	50,405
Flue Gas Emissions			
Nitrogen Oxides, NO_x, lb/MMBtu (HHV)	0.09	0.0127	0.0081
Uncontrolled SO_2, lb/MMBtu (HHV) - based on 80/20 blend	7.49	5.25	5.312
Boiler Outlet SO_2, lb/MMBtu (HHV) [See Note 3]	0.78	0.1150	0.1636
Stack SO_2 lb/MMBtu, (HHV)	0.15	0.058	0.07
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.0024	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.0127	0.0081
Opacity, percent	10	0.07	0.08
Ammonia (NH_3) Slip, ppmvd	2.0	0.27	
Ammonia feed rate, gal/hr	NA	3.42	1.09
Lead, lb/MMBtu	2.60×10^{-5} (max)	4.424×10^{-7}	
Mercury (fuel and limestone), µg/g	NA	0.05	
Mercury, lb/TBtu (at stack)	10.5 (max)	< 0.07385	
Total Mercury Removal Efficiency, percent	No requirement	98 (See Note 2)	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	$< 5.3 \times 10^{-6}$	
Dioxins / Furans	No Limit	NOT TESTED	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from FW data).
NOTE 2: Refer to Section 4.3.4.1 of Test Report 4 for basis.
NOTE 3: Design boiler outlet SO_2 emission rate based on 85% removal of SO_2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of the FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.
NOTE 5: These components were not captured for this test - average results from Test #1 and Test #2 are indicated.

The boiler and SDA SO_2 removal efficiencies at full load for each test are summarized in Tables 7-5 through 7-8 below.

TABLE 7-5 - SO2 REMOVAL EFFICIENCIES - 100% PITT 8 FUEL
100% Load

Parameter	Design Basis	January 13, 2004 Test	January 14, 2004 Test
Percent of total SO_2 removed by boiler	85.0 typical, with range of 75 - 90	96.8	95.8
Percent of total SO_2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.8	2.7
Percent of Total SO_2 Removed	97.1	98.6	98.5
Percent of SO_2 entering SDA removed in SDA	81.0 typical with range 90 – 71	56.9	63.5
Boiler Calcium to Sulfur Ratio	< 2.88	1.77	1.86

TABLE 7-6 - SO2 REMOVAL EFFICIENCIES - 50/50 BLEND PITT 8 COAL AND PET COKE
100% Load

Parameter	Design Basis	January 27, 2004 Test	January 28, 2004 Test
Percent of total SO_2 removed by boiler	85.0 typical, with range of 75 - 90	97.5	96.8
Percent of total SO_2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.3	1.9
Percent of Total SO_2 Removed	97.1	98.8	98.7
Percent of SO_2 entering SDA removed in SDA	81.0 typical with range 90 – 71	54	60.3
Boiler Calcium to Sulfur Ratio	< 2.88	1.7	2.25

TABLE 7-7 - SO2 REMOVAL EFFICIENCIES - ILLINOIS 6 COAL
100% Load

Parameter	**Design Basis**	**June 8, 2004 Test**	**June 9, 2004 Test**
Percent of total SO_2 removed by boiler	85.0 typical, with range of 75 - 90	94.9	95.0
Percent of total SO_2 removed by SDA	12.1 typical, with range 22.1 – 7.1	3.17	3.7
Percent of Total SO_2 Removed	97.1	98.0	98.6
Percent of SO_2 entering SDA removed in SDA	81.0 typical with range 90 – 71	61.0	72.0
Boiler Calcium to Sulfur Ratio	< 2.88	2.68	2.43

TABLE 7-8 - SO2 REMOVAL EFFICIENCIES - 80/20 BLEND PET COKE AND PITT 8 COAL
100% Load

Parameter	**Design Basis**	**August 10, 2004 Test**	**August 11, 2004 Test)**
Percent of total SO_2 removed by boiler	85.0 typical, with range of 75 - 90	97.8	96.9
Percent of total SO_2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.1	1.8
Percent of Total SO_2 Removed	97.1	98.9	98.7
Percent of SO_2 entering SDA removed in SDA	81.0 typical with range 90 – 71	49.5	57.0
Boiler Calcium to Sulfur Ratio	< 2.88	2.29	2.29

Note that the design operating condition of the unit is to remove 85 percent of the SO_2 in the boiler, with the balance to make the permitted emission rate removed in the SDA. JEA has chosen to operate at a much higher boiler SO_2 removal rate than design. Part of the reason for this operating mode is that reliability of the limestone feed system during and after the startup period was inadequate, resulting in a substantial number of periods with excess SO_2 emissions. Over time, the operations group has learned that if limestone feed is higher than normally desired, the likelihood of excess emissions during an upset is reduced. Additionally, control of the AQCS slurry density at the desired density levels has been difficult due to some instrumentation and control issues that are not completely resolved yet. Modifications to increase the reliability and consistency of limestone feed are scheduled to be complete in late 2005, which should permit a change toward lower boiler SO_2 removal and increased SDA SO_2 removal.

7.4.4 Partial Load Test Results

The results of the part load tests are summarized in Tables 7-9 through 7-12 below.

TABLE 7-9 - PART LOAD TEST RESULTS - 100% PITTSBURGH 8 FUEL

Parameter	January 15	January 16	
Percent Load	80%	60%	40%
Unit Capacity (MW)	240	180	120
Total Main Steam Flow, lb/hr	1,435,543	1,070,747	738,397
Main Steam Temperature, deg F	1,003	998	999
Main Steam Pressure, psig	2,400.6	1,800.4	1,300.4
Cold Reheat Steam Temperature, deg F	576.6	572.7	565.9
Hot Reheat Steam Temperature, deg F	1,005	1,006	1,004
NOx, lb/MMBtu	0.080	0.072	0.082
CO, lb/MMBtu	0.044	0.118	0.053
SO2, lb/MMBtu	0.082	0.081	0.108
Opacity, percent	1.0	1.5	1.4

TABLE 7-10 - PART LOAD TEST RESULTS - 50/50 BLEND PITT 8 COAL AND PET COKE

Parameter	January 29	January 30	January 31
Unit Capacity (MW)	240	180	120
Percent MCR Load	80%	60%	40%
Capacity Calculation (percent)	76.6	58.0	38.2
Total Main Steam Flow, lb/hr	1,442,226	1,049,633	715,464
Main Steam Temperature, deg F	1,004	993	997
Main Steam Pressure, psig	2,340	1,701	1,062
Cold Reheat Steam Temperature, deg F	577.5	558.02	573.64
Hot Reheat Steam Temperature, deg F	1,006	1,011	999
NOx, lb/MMBtu	0.04	0.043	0.033
CO, lb/MMBtu	0.024	0.0276	0.08
SO2, lb/MMBtu	0.08	0.067	0.109
Opacity, percent	1.4	1.1	0.8

TABLE 7-11 - PART LOAD TEST RESULTS - ILLINOIS 6 COAL

Parameter	June 9	June 8	June 9
Percent Load	80%	60%	40%
Unit Capacity (MW)	240	180	120
Capacity Calculation (percent)	82.21	55.50	38.27
Total Main Steam Flow, lb/hr	1,541,871	1,087,192	715,411
Main Steam Temperature, deg F	1,001	1,002	1,001
Main Steam Pressure, psig	2,400	1,700	1,200
Cold Reheat Steam Temperature, deg F	561	575	561
Hot Reheat Steam Temperature, deg F	1,007	966	1,004
NOx, lb/MMBtu	0.064	0.053	0.078
CO, lb/MMBtu	0.031	0.0338	0.138
SO2, lb/MMBtu	0.079	0.144	0.108
Opacity, percent	1.3	1.6	1.4

TABLE 7-12 - PART LOAD TEST RESULTS - 80/20 BLEND PET COKE AND PITT 8 COAL

Parameter	Aug. 12	Aug. 13
Unit Capacity (MW)	240	180
Percent MCR Load	80%	60%
Capacity Calculation (percent)	76.51	54.69
Total Main Steam Flow, lb/hr	1,393,557	1,021,784
Main Steam Temperature, deg F	980.55	980.62
Main Steam Pressure, psig	2,200.14	1,450.21
Cold Reheat Steam Temperature, deg F	579.46	595.45
Hot Reheat Steam Temperature, deg F	984.03	992.10
NOx, lb/MMBtu	0.027	0.018
CO, lb/MMBtu	0.0147	0.0218
SO2, lb/MMBtu	0.054	0.058
Opacity, percent	1	1

7.5 Boiler Efficiency Tests

For each test, the unit was operated at a steady turbine load of approximately 300 MW (100% MCR) for two (2) consecutive days as prescribed in the Test Protocol. During these two days, data were recorded via the PI (Plant Information) System and were also collected by independent testing contractors. These data were then used to determine the unit's boiler efficiency.

7.5.1 Calculation Method

The boiler efficiency calculation method was based on a combination of the abbreviated heat loss method as defined in the ASME Power Test Code (PTC) 4.1, 1974, reaffirmed 1991, and the methods described in ASME PTC 4. The method was modified to account for the heat of calcination and sulfation within the CFB boiler SO_2 capture mechanism. The methods have also been modified to account for process differences between conventional and fluidized bed boilers to account for the addition of limestone. These modifications account for difference in the dry gas quantity and the additional heat loss/gain due to calcination / sulfation. A complete description of the modified procedures is included in Section 4.2 of the Fuel Capability Demonstration Test Protocol. Some of the heat losses included losses due to the heat in dry flue gas, unburned carbon in the bed ash and the fly ash, and the heat loss due to radiation and convection from the insulated boiler surfaces.

7.5.2 Data and Sample Acquisition

During the tests, permanently installed plant instrumentation was used to measure most of the data which were required to perform the boiler efficiency calculations. The data were collected electronically utilizing JEA's Plant Information (PI) system. Additional data required for the boiler efficiency calculations were collected by two independent testing contractors, Power Generation Technologies (PGT), and Clean Air Engineering (CAE).

The majority of the data utilized in the boiler efficiency calculation and sulfur capture performance, such as combustion air and flue gas temperatures and flue gas oxygen content, were stored and retrieved by the PI system, as noted above. Data for the as-fired fuel, limestone, and resulting bed ash, fly ash, and exiting flue gas constituents were provided via laboratory analyses. Samples were taken in the following locations by PGT and forwarded to a lab for analysis.

<u>Lime:</u>

Lime slurry samples were taken from the sample valve located on the discharge of the lime slurry transfer pump. This valve is located in the AQCS Spray Dryer Absorber (SDA) pump room.

<u>Fly ash:</u>

Fly ash samples were taken by two different methods.

1) Flyash was taken by isokinetic sampling at the inlet to the SDA. These samples were taken to determine ash loading rates and also obtain samples for laboratory analysis of ash constituents.
2) Flyash was also taken by grab sample method in two different locations. One grab sample was taken every hour at a single air heater outlet hopper and another grab sample at a single bag house fabric filter hopper.

<u>Fuel:</u>

Fuel samples were taken from the sample port at the discharge end of each gravimetric fuel feeder. The fuel samples were collected using a coal scoop inserted through the 4 inch test port at each operating fuel conveyor.

Limestone:

Limestone samples were taken from the outlet of each operating limestone rotary feeder. The samples were collected using a scoop passed into the flow stream of the 4 inch test ball valve in the neck of each feeder outlet.

Bed Ash:

Bed ash samples were taken from each of the operating stripper cooler rotary valve outlets. The samples were taken by passing a stainless steel scoop through the 4 inch test port at each operating stripper cooler.

All of the samples were labeled and transferred to a lab for analysis. The average values were determined and used as input data for performing the boiler efficiency calculation.

7.6 AQCS Inlet and Stack Tests

7.6.1 System Description

The Unit 2 AQCS consists of a single, lime-based SDA and a multi-compartment PJFF. The SDA has sixteen independent dual-fluid atomizers. The PJFF has eight isolatable compartments. The AQCS system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Flyash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime, which is delivered dry to the station, into a hydrated lime [$Ca(OH)_2$] slurry, which is fed to the atomizers as a supplemental reagent.

7.6.2 Emissions Test Methods

The emissions test methods used for the demonstration test were based upon utilizing 40 CFR 60 based testing methods or the plant CEMS. The emissions tests were conducted by CAE. The following test methods were utilized:

- Particulate Matter at SDA Inlet – USEPA Method 17
- Particulate Matter at Stack – USEPA Method 5
- Oxides of Nitrogen at Stack – Plant CEMS
- Sulfur Dioxide at SDA Inlet – USEPA Method 6C
- Sulfur Dioxide at Stack – Plant CEMS
- Carbon Monoxide at Stack – Plant CEMS
- Ammonia at Stack – Conditional Test Method 027
- Lead at Stack – USEPA Method 29
- Mercury at SDA Inlet – Ontario Hydro Method
- Fluorine at Stack – USEPA Method 13B
- Dioxin/Furans (PCDD/F) – USEPA Method 23

7.6.3 Continuous Emission Monitoring System

The plant CEMS was utilized for measurement of gaseous emissions as a part of the fuel capability demonstration, as listed above. The CEMS equipment was integrated by KVB-Entertec (now GE Energy Systems). The system is a dilution extractive system consisting of Thermo Environmental NO_x, SO_2, and CO_2 analyzers. The test data from the CEMS originated from the certified Data Acquisition Handling System (DAHS).

8.0 CAPITAL COSTS

8.1 Capital Cost History/Overview

At the time JEA and the DOE signed the Cooperative Agreement for the Large-Scale CFB Combustion Demonstration Project for Northside Unit 2 in September 1997, the preliminary budget estimate for Repowering Unit 2 with CFB boiler technology, plus one-half of the cost of the associated common facilities, totaled $305, 773,774. This preliminary budget estimate was used as the basis for cost sharing throughout the project life.

The preliminary project capital cost estimate increased due to refined scope definitions, improved cost estimates, and scope growth. To identify and quantify the magnitude of this increase, the project "Baseline" estimate was developed in October 2000. The "Baseline" or "Control" estimate was the joint effort by the key principles making up the project team. Estimates, based on firm scope and significant detail design, were developed by JEA, FW, B&V, FGS, and ZCC for their areas of the project. This estimate resulted in a revised budget for Unit 2 and one-half of the common facilities to $328,878,487.

At project completion, the actual capital cost for Unit 2 and one-half of the associated common facilities totaled $321,392,624, only about 5% above the original preliminary budget estimate. A breakdown of these costs by DOE Phase and Task is provided in Appendix D.

DOE financial support and limitations on DOE funding, as set forth in the Cooperative Agreement, were tied to the preliminary budget estimate. Within that budget of $305,773,774, DOE would share fifty percent (50%) of Phase 1B (Design) cost up to $11,484,482; JEA's actual portion of Phase 1B at completion totaled $22,549,532. Within Phase 2 (Construction and Start-up), DOE would share at a rate of twenty eight point three percent (28.3%) up to $59,243,317; JEA's actual portion of Phase 2 at completion totaled $228,115,293. During Phase 3 (Operations), the DOE share would total $2,344,655. The Phase 3 funds were tied to a milestone schedule for final issue of the demonstration test reports. At project completion the DOE cost share in the project is expected to be a total of $73,072,464, with the JEA cost share being $250,664,825.

8.2 Capital Improvement Projects - Phase 1

Problems with Unit 2 reliability and maintainability were encountered early in plant operations. As a result, JEA began targeting capital funds, in addition to O&M funds being expended, to mitigate and resolve many of the problems being experienced. These projects were identified as Phase 1 Completion Modifications, and are described in more detail in the Start-up Modifications Report, which is available on the DOE website at the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/Start-Up%20Modifications%20Report_final.pdf

These Phase 1 Completion Modifications, hereinafter referred to as Capital Improvement Projects, were executed during FY 02/03 at a capital cost of $5,697,156. A description of these projects and associated costs is provided in Appendix D.

8.3 Capital Improvement Projects - Phase 2

Continuing significant operating and reliability issues lead to the identification of additional improvement projects, referred to as Phase 2 Capital Improvement Projects. These projects were implemented during FY 03/04 at a capital cost of $7,138,138. A description of these projects and associated costs is also provided in Appendix D.

8.4 Capital Improvement Projects Going Forward

Although the Cooperative Agreement between DOE and JEA is expected to be completed in April 2005, JEA is continuing to proactively investigate and implement (where appropriate) capital outlays to improve EAF and maintainability of the repowered units.

8.5 Commercialization of Large Scale CFB Combustion Technology

The JEA Large Scale CFB Combustion Demonstration Project has demonstrated the successful commercial operation of a 300 MW class CFB boiler firing both domestic coals and petroleum coke, and coal/coke blends. The operating data summarized in Section 5 of this report confirms that the Unit 2 CFB boiler is capable of routinely supporting full load operation of Unit 2 while achieving stack emissions below permit limits. The performance test results in Section 7 of this report confirm that the as-tested full load boiler efficiencies on various fuels were at or above the design values developed by FW, and are competitive with the boiler efficiencies achieved by other commercially available boiler technologies of this size.

However, the operating data in Section 5 also indicates that the EAF for Unit 2 during the two year demonstration period for the project was significantly lower than industry average values, based on a comparison to NERC/GADS data. The majority of the lost MW hours were caused by boiler related problems, and JEA has spent over 12 million dollars on capital improvement projects during the two year demonstration period to improve the reliability and maintainability of the Unit 2 CFB boiler and AQCS system. Refer to Section 6 of this report for a description of some of the significant modifications that have been made. The associated capital costs are summarized in this Section 8 of the report. In addition, JEA anticipates that significant additional capital expenditures will be required over the next 5 years, primarily on the boilers, to raise the EAF of Units 1 and 2 to near industry average values.

The most significant boiler related problem affecting EAF encountered during the demonstration period has been agglomeration and superheater tube failures in the Intrex, as described in Section 6 of this report. Investigations by JEA and FW of the issues involved and long term modifications to mitigate these issues on the Northside CFB boilers are ongoing. Options being considered include removal of the superheater surface from the Intrex. FW has already concluded that the Intrex design is not viable, and is no longer offering this design feature on new CFB boilers.

APPENDICES

APPENDIX A - Drawings

OVERALL PLOT PLAN

CMA-S1000	Site Arrangement
4600-1-51-004	Overall plot plan

CFB BOILERS

43-7587-5-51	GENERAL ARRANGEMENT UNIT 2 SIDE ELEVATION
43-7587-5-52	GENERAL ARRANGEMENT UNIT 2 ISO VIEW (FRONT)
43-7587-5-53	GENERAL ARRANGEMENT UNIT 2 ISO VIEW (RIGHT SIDE)
43-7587-5-54	GENERAL ARRANGEMENT UNIT 2 ISO VIEW (LEFT SIDE)
43-7587-5-55	GENERAL ARRANGEMENT UNIT 2 ISO VIEW (REAR)
43-7587-5-20	STEAM GENERATOR GENERAL ARRANGEMENT CROSS SECTION

AIR QUALITY CONTROL SYSTEM

3847-1-100	GEN ARRANGEMENT PLAN
3847-1-101	GEN ARRANGEMENT ELEVATION
3847-1-102	GEN ARRANGEMENT ELEVATION
3847-1-103	GEN ARRANGEMENT ELEVATION

WATER MASS BALANCE DIAGRAM

WMB-1	WATER MASS BALANCE, ANNUAL AVERAGE, CELL 1 OF BSA ONLY

APPENDIX B - Major Equipment List

The Equipment List on the following pages lists the major equipment associated with the Repowering Project and is listed by the JEA GEMS (or System) Code. Since the P&ID's are defined and numbered by their associated GEMS code, the equipment is also listed by P&ID. The quantity, percent capacity, and redundancy is indicated for each item of equipment. This information is indicated for Unit 2, Common, and Unit 1 equipment, since some items of equipment serve as an installed back-up for both units.

JEA Large-Scale CFB Demonstration Project
Major Equipment List

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
AB	INSTRUMENT AIR DRYERS		3		Nominal 50% Capacity Each	Serve Units 1, 2, and 3
AC	AIR COMPRESSORS		6		Nominal 25% Capacity Each	Provide Service and Instrument Air for Units 1, 2, and 3
BB	STEAM GENERATOR	1		1		
BB	STEAM DRUM	1		1		
BC	SECONDARY AIR TUBULAR AIR HEATER	1		1		
BC	PRIMARY AIR TUBULAR AIR HEATER	1		1		
BF	ELBOW DUCT BURNERS	3		3		For Start-up Only
BF	ABOVE BED BURNERS	3		3		100 MMBtu per Hour each
BI	SOOTBLOWER PRIMARY SUPERHEATER	8		8		
BI	SOOTBLOWER FINAL REHEATER	6		6		
BI	SOOTBLOWER REHEATER	6		6		

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
BI	SOOTBLOWER ECONOMIZER	16		16		
BK	BOILER BLOWDOWN DRUM	1		1		
BN	PRIMARY AIR FAN	2		2	50% Capacity Each	
BN	SECONDARY AIR FAN	2		2	50% Capacity Each	
BN	PRIMARY AIR FAN LUBE OIL SKID	2		2		One per Fan
BO	INDUCED DRAFT FAN	2		2	50% Capacity Each	
BO	ID FAN INLET ISOLATION DAMPER	2		2		One per Fan
BO	ID FAN OUTLET ISOLATION DAMPER	2		2		One per Fan
BO	CONCRETE CHIMNEY		1			With Separate Flue for Each Unit
EF	MCC/LOAD CENTER/SWITCHGEAR	1 LOT	1 LOT	1 LOT		Essentially all MCC's, Load Centers, and Switchgear were replaced for Unit 2, Common, and Unit 1 Equipment
FG	FUEL UNLOADING DOCK		1			
FH	COINTINUOUS SHIP UNLOADER		1			
FH	COKE/COAL BELT CONVEYORS TO DOMES		7			Single String of Conveyors to Storage Domes

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
FH	COKE/COAL STORAGE DOMES		2		85,000 Tons per Dome	
FH	RADIAL STACKER RECLAIMER		2		100% Capacity Each	One per Dome - Serve Units 1 and 2
FH	SILO FILL COKE/COAL CONVEYORS		8		100% Capacity Each	Two Full Capacity Strings of Conveyors - Serve Units 1 and 2
FH	COKE/COAL CRUSHER		2		100% Capacity Each	Serve Units 1 and 2
FH	COKE/COALTRAVELING TRIPPER		2		100% Capacity Each	Serve Units 1 and 2
FN	BOILER COAL/COKE SILO	5		5		
FN	COKE/COAL DRAG CONVEYOR	2		2		For Rear Wall Feed
FN	COKE/COAL GRAVAMETRIC FEEDER	8		8		
GA	GENERATOR	1		1		
GC	MAIN SEAL OIL PUMP	1		1		
GC	EMERGENCY SEAL OIL PUMP	1		1		
GC	SEAL OIL VACUUM PUMP	1		1		
GC	SEAL OIL TANK	1		1		
GI	STATOR COOLING WATER PUMP	2		2	100% Capacity Each	

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
GI	DEIONIZER	1		1		
GI	STATOR COOLING WATER STORAGE TANK	1		1		
GI	STATOR COOLING WATER COOLERS	2		2	100% Capacity Each	
HB	NASH VACUUM PUMP	1	1	1	100% Capacity Each	
HD	BITTER WATER PUMP	1		1		
HD	BOILER FILL PUMP	1				Serves Units 1, 2, and 3
HF	CONDENSATE BOOSTER PUMP	2		2	100% Capacity Each	With Variable Speed Fluid Drives
HF	BED ASH COOLING WATER PUMP	2		2	100% Capacity Each	
HF	DEAERATOR (FWH 3) STORAGE TANK	1		1		
HF	DEAERATOR (FWH 3) HEATER SECTION	1		1		
HF	FEED WATER HEATER NO. 4	1		1		
HF	FEED WATER HEATER NO. 5	1		1		
HF	FEED WATER HEATER NO. 6	1		1		
HK	HEATER DRAIN PUMP	2		2	100% Capacity Each	

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
HK	FEED WATER HEATER NO. 6 HOTWELL	1		1		
HP	SULFURIC ACID MIXING SKID	1				
HP	CAUSTIC MIXING SKID	1				
HP	POLISHER RECYCLE PUMP	1		1		
HP	POLISHER SLUICE PUMP			1		
HP	POLISHER REGENERATION WATER PUMP	1				
HP	CAUSTIC RECYCLE PUMP	1				
HP	CONDENSATE POLISHER VESSEL	3		3	50% Capacity Each	
HP	CONDENSATE POLISHER SEPARATION AND ANION REGENERATION VESSEL	1		1		
HP	CONDENSATE POLISHER CATION REGENERATION VESSEL	1		1		
HP	CONDENSATE POLISHER MIX AND HOLD VESSEL	1		1		
HP	CONDENSATE POLISHER HOT WATER TANK	1		1		
HP	WASTE INSPECTION TANK	1				
HP	POLISHER RESIN TRAP	3		3		One per Polisher Vessel

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
IB	TRAVELING WATER SCREENS	2		2	50% Capacity Each	
IB	SCREEN WASH PUMPS		2			Serve Units 1, 2, and 3
MA	BOILER FREIGHT ELEVATOR	1		1		
MJ	BOILER SAMPLE PANEL CHILLER	1		1		
MJ	BOILER SAMPLE PANEL	1		1		
MJ	SAMPLE PANEL	1				
MJ	SAMPLE CHILLER	1				
NA	FLY ASH SILO	1		1		Fly Ash from either Unit 2 or Unit 1 can be directed to either silo
NA	FLY ASH SILO FILTER/SEPARATOR	2		2	100% Capacity Each	Fly Ash from either Unit 2 or Unit 1 can be directed to either silo
NA	FLY ASH SILO VENT FILTER	1		1		
NA	AQCS RECYCLE BIN FILTER/SEPARATOR	1		1		
NA	FLY ASH HEAD CIRCULATION PUMP	1		1		
NA	DENSE ASH SLURRY MIXING TANK FEED PUMP	2		2	50% Capacity Each	
NA	STANDBY AIR COMPRESSOR		1			

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
NA	PRIMARY AIR COMPRESSOR		1			
NA	FLY ASH SLURRY MIXING TANK	1		1		
NA	FLY ASH VACUUM EXHAUSTER		4		100% Capacity Each	Crosstied to serve either Unit 2 or Unit 1
NA	BED ASH CROSS CONVEYOR		2			Between Unit 2 and Unit 1 Bed Ash Silo Outlets
NA	BED ASH CLINKER GRINDERS	1		1		Above Dense Ash Slurry Mixing Tank
NA	DENSE ASH SLURRY MIXING TANK	1		1		
NA	DENSE ASH HEAD CIRCULATION PUMP	1		1		
NA	DENSE ASH SLURRY BOOSTER PUMP	2		2	100% Capacity Each	
NA	DENSE ASH SLURRY PISTON DIAPHRAGM PUMP		2		100% Capacity Each	
NA	EMERGENCY FLUSH PUMP		1			
NB	BED ASH SILO	1		1		Bed Ash from either Unit 1 or Unit 2 can be directed to either silo
NB	BED ASH PRESSURE AIRLOCK VESSEL	4		4		
NB	BED ASH SURGE HOPPER	1		1		
NB	SIDE WALL STRIPPER/ COOLER	2		2		

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
NB	FRONT WALL STRIPPER COOLER	2		2		
NB	BED ASH SURGE HPR. VENT FILTER	1		1		
NB	BED ASH SILO VENT FILTER	1		1		
NB	ASH CLR. DISCHARGE CONVEYOR	4		4		One from each Stripper Cooler
NB	BED ASH GATHERING CONVEYOR	2		2		
NB	BED ASH CLINKER GRINDER	2		2		Above Bed Ash Surge Hopper
NB	BED ASH TRANSPORT BLOWER		3		100% Capacity Each	Crosstied to serve either Unit 2 or Unit 1
NB	BED ASH SURGE HOPPER VENT FILTER EXHAUST FAN	1		1		
NL	REUSE WATER ACID FEED PUMP SKID		1			
NL	REUSE WATER INHIBITOR FEED PUMP SKID		1			
NL	REUSE WATER CHEMICAL FEED STATIC MIXER		1			
NL	REUSE WATER SUPPLY PUMP		2		100% Capacity Each	
NL	CSU REUSE WATER BOOSTER PUMP		1			
NL	REUSE WATER STORAGE TANK		1			

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
NN	BSA SUMP		4			
NN	BSA SUMP PUMPS		8			Two Pumps per Sump
NN	BSA LEACHATE DETECTION SUMP		4			
NN	BSA LEACHATE DETECTION SUMP PUMP		8			Two Pumps per Sump
NN	BSA POND EFFLUENT SUMP		1			
NN	BSA POND EFFLUENT SUMP PUMP		2			
NN	WASTEWATER COLLECTION SUMP 12		1			
NN	WASTEWATER COLLECTION SUMP 12 SUMP PUMP		2			
NN	FUEL STORAGE DOME SUMP 13		1			
NN	FUEL STORAGE DOME SUMP 13 SUMP PUMP		2			
NN	SUBSURFACE DRAIN SUMP		3			
NN	SUBSURFACE DRAIN SUMP PUMP		6			Two Pumps per Sump
NN	BOILER SUMP	1		1		
NN	BOILER SUMP PUMP	2		2		

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
NN	AQCS SUMP	1		1		
NN	AQCS SUMP PUMP	2		2		
NN	ELEVATOR SHAFT SUMP PUMP	1		1		
QB	BOILER FEED PUMP	2		2	50% Capacity Each	One motor driven, one turbine shaft driven. With variable speed fluid drives.
QB	BOILER FEED PUMP SEAL WATER LEAK OFF RECOVERY TANK	1		1		
QF	FEED WATER HEATER NO. 2	1		1		
QF	FEED WATER HEATER NO. 1	1		1		
RA	AQCS GLYCOL CIRCULATING PUMP		2		100% Capacity Each	Serve Unit 2 and Unit 1
RA	AQCS ATOMIZING AIR COMPRESSOR	1	1	1	100% Capacity Each	
RA	AQCS ATOMIZING AIR RECEIVER		1			Serves Unit 2 and Unit 1
RA	AQCS GLYCOL/WATER SURGE TANK		1			Serves Unit 2 and Unit 1
RA	ATOMIZING AIR COMPRESSOR INLET AIR FILTER/SILER.	1	1	1		One per Compressor
RA	ATOMIZING AIR COMPRESSOR UNLOADING SILER.	1	1	1		One per Compressor
RA	LIME SLURRY FEED PUMP	2		2	100% Capacity Each	

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
RA	RECYCLE SLURRY TRANS. PUMP	2		2	100% Capacity Each	
RA	FEED SLURRY TRANS. PUMP	2		2	100% Capacity Each	
RA	FEED SLURRY PUMP	2		2	100% Capacity Each	
RA	AQCS FLUIDIZING AIR BLOWER	3		3	50% Capacity Each	
RA	AQCS FLUIDIZING AIR HEATER	3		3	50% Capacity Each	
RA	LIME SLURRY STORAGE TANK AGITATOR	1		1		
RA	RECY SLURRY STORAGE TANK AGITATOR	1		1		
RA	RECY SLURRY MIX TANK AGITATOR	1		1		
RA	LIME SLURRY STORAGE TANK	1		1		
RA	RECYCLE SLURRY MIX TANK	1		1		
RA	RECYCLE SLURRY STORAGE TANK	1		1		
RA	FLY ASH RECYCLE STORAGE BIN	1		1		
RA	FEED SLURRY HEAD TANK	1		1		
RA	SDA BIN ACTIVATOR	1		1		

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
RA	FLY ASH RECYCLE FEEDER	2		2	100% Capacity Each	
RA	SDA ASH CONVEYOR	1		1		
RA	SDA EMERGENCY DISCHARGE CONVEYOR	1		1		
RA	SDA ASH DELUMPER	1		1		
RA	SDA IMPACTOR	3		3		
RB	FABRIC FILTER COMPARTMENT	8		8		
RB	AQCS INSTRUMENT AIR DRYER		2		100% Capacity Each	Serve Unit 2 and Unit 1
RH	LIMESTONE STACK-OUT CONVEYOR		1			
RH	LIMESTONE FEED CONVEYORS TO LS PREP		3			One per Dryer/Mill Train
RH	LS PLANT AIR COMPRESSOR		2			Serve Unit 2 and Unit 1
RH	LS AIR HEATER COMBUSTION AIR FAN		3			One per Dryer/Mill Train
RH	LS DRYER/MILL DUST COLL EXHAUST FAN		3			One per Dryer/Mill Train
RH	LS PREP. DUST COLLECTOR EXHAUST FAN		3			One per Dryer/Mill Train
RH	LS PRODUCT PNEUMATIC BLOWER		3			One per Dryer/Mill Train

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
RH	LS PLANT AIR RECEIVER		2			Serve Unit 2 and Unit 1
RH	LIMESTONE PRODUCT SURGE BIN		3			One per Dryer/Mill Train
RH	LS AIR HEATER		3			One per Dryer/Mill Train
RH	LIMESTONE PREP. DUST COLLECTOR		3			One per Dryer/Mill Train
RH	LIMESTONE DRYER/MILL DUST COLL		3			One per Dryer/Mill Train
RH	LIMESTONE PRODUCT SCREEN		6			Two per Dryer/Mill Train
RH	LS PLANT AIR DRYER		2			Serve Unit 2 and Unit 1
RH	LIMESTONE PROD. ELEV CONVEYOR		3			One per Dryer/Mill Train
RH	LIMESTONE SCREEN FEEDER		3			One per Dryer/Mill Train
RH	LS SCREEN PRODUCT SCREW CONV.		3			One per Dryer/Mill Train
RH	LIMESTONE DRYER/MILL		3		100% Capacity Each for 1 Unit	Each Dryer/Mill Train can supply either Unit 2 or Unit 1
RH	RAW LIMESTONE IMPACTOR		3			One per Dryer/Mill Train
RL	AQCS MILL RECYCLE FEED PUMP		2		100% Capacity Each	Serve Unit 2 and Unit 1
RL	AQCS LIME SLURRY TRANSFER PUMP		4		100% Capacity Each	Serve Unit 2 and Unit 1

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
RL	AQCS LIME SLURRY TRANS. TANK AGITATOR		2			Serve Unit 2 and Unit 1
RL	AQCS LIME STORAGE SILO		1			Serves Unit 2 and Unit 1
RL	AQCS LIME SLURRY TRANSFER TANK		2			Serves Unit 2 and Unit 1
RL	AQCS MILL SEPARATING CHAMBER		2			Serves Unit 2 and Unit 1
RL	AQCS LIME STORAGE SILO BIN ACTIVATOR		1			Serves Unit 2 and Unit 1
RL	AQCS LIME STORAGE SILO DUST COLLECTOR		1			Serves Unit 2 and Unit 1
RL	AQCS MILL VENT SCRUBBER		2			Serves Unit 2 and Unit 1
RL	AQCS VERTICAL BALL MILL SLAKER		2			Serves Unit 2 and Unit 1
RN	LIMESTONE BLOWER	3		3	33-1/3% Capacity Each	
RN	STANDBY LIMESTONE BLOWER	1		1		
RN	LIMESTONE SILO	1		1		
RN	LIMESTONE FILTER/RECEIVER	3		3		
RN	LIMESTONE SILO VENT FILTER	1		1		
RN	LIMESTONE FILTER/REC. EXHAUSTER	3		3		

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
RN	LIMESTONE ROTARY FEEDER	3		3		
RN	LIMESTONE ROTARY AIRLOCK FEEDER	6		6		
RN	LIMESTONE ROTARY VALVE	3		3		
SI	INTREX™	3		3		
SI	INTREX™ BLOWER	3		3	50% Capacity Each	
SI	SEAL POT BLOWER	3		3	50% Capacity Each	
SJ	ERV SILENCER	1		1		
SK	CYCLONE	3		3		
SL	ECONOMIZER	1		1		
TG	STEAM TURBINE - LP	1		1		
TH	STEAM TURBINE - HP/IP	1		1		
TI	STEAM PACKING EXHAUSTER	1		1		
TJ	TURB LUBE OIL HEAT EXCHANGERS	2		2	100% Capacity Each	
TJ	TURBINE LUBE OIL CONDITIONER	2		2		One Bowser, One Turbo-Toc

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
TJ	TURBINE LUBE OIL TANK	2		2		One Operating Tank, One Storage Tank
TJ	TURBINE LUBE OIL PUMP	3		3		Two AC, One DC
TN	TURBINE ELECTRO-HYDRAULIC CONTROL UNIT	1		1		
UE	HYDRAZINE FEED PUMP	1		1		
UE	AMMONIA FEED PUMP	1		1		
UE	PHOSPHATE FEED PUMP	2		2	100% Capacity Each	
UE	PHOSPHATE STORAGE TANK	1		1		
UE	PHOSPHATE STG. TANK AGITATOR	1		1		
UR	AMMONIA PUMP	1	1	1	100% Capacity Each	Common Shared Spare
UR	AMMONIA STORAGE TANK		1			Serves Units 2 and 1
WF	DEMINERALIZED WATER TRANSFER PUMPS		2			Added Demin Water from SJRPP for Units 1, 2, and 3
XE	CONDENSATE PUMP	2		2	100% Capacity Each	
XE	CONDENSER	1		1		
XE	DEBRIS FILTERS	2		2	50% Capacity Each	

GEMS SYSTEM	DESCRIPTION	QUANTITY			CAPACITY	REMARKS
		UNIT 2	COMMON	UNIT 1		
XJ	RIVER WATER BOOSTER PUMP	2		2	100% Capacity Each	
XK	CLOSED COOLING WATER PUMP	2		2	100% Capacity Each	
XK	CLOSED COOLING WATER BOOSTER PUMP	2		2	100% Capacity Each	
XK	CLOSED COOLING WATER SURGE TANK	1		1		
XK	CLOSED COOLING WATER PLATE HEAT EXCHANGER	2		2	100% Capacity Each	
XL	CIRCULATING WATER PUMP	2		2	50% Capacity Each	

APPENDIX C - Unit 2 Operating Data

FILE: (0)JEADATA DRAKE	CALENDAR 2003	CALENDAR 2004	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03
FUEL HEAT CONTENT																	
NS-2 PETCOKE HEAT CONTENT-BTU/LB	14,107	13,949	14,133	13,893	14,240	14,321	14,257	14,182	14,042	13,932	14,273	14,215	14,044	14,263	14,002	13,973	13,950
NS-2 COAL HEAT CONTENT-BTU/LB	12,827	11,907	13,044	12,874	12,901	12,985	13,012	12,943	13,092	13,152	13,064	13,077	13,125	12,674	12,328	12,380	12,156
NS-2 PETCOKE %S	5.28	4.53	5.43	4.77	4.13	3.73	5.84	6.66	5.55	5.23	4.25	5.71	5.87	5.42	5.13	5.97	4.02
NS-2 COAL %S	2.52	2.62	2.65	2.82	2.76	2.42	2.39	2.44	2.54	2.48	2.65	2.73	2.63	2.30	2.36	2.57	2.69
NS-2 PETCOKE %ash	0.42	0.71	0.36	0.42	0.38	0.34	0.41	0.27	0.41	0.49	0.47	0.34	0.34	0.36	0.63	0.57	0.46
NS-2 COAL %ash	8.10	8.81	7.84	8.14	8.11	8.03	7.86	7.61	7.70	7.79	7.92	8.16	8.15	8.33	8.10	8.25	9.28
NS-2 OPER DATA (GROSS CAP) 297.5			297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5
GROSS MWH GENERATED	1,791,221	1,459,351	122,429	70,505	114,822	130,431	144,719	188,780	50,944	196,907	207,850	195,162	123,728	134,363	164,859	41,415	212,063
HOUSE LOAD MWH (ON-LINE)	117,240	101,924	10,444	10,570	8,577	9,595	10,924	14,937	4,145	14,266	11,357	11,159	7,546	8,048	10,568	3,648	11,049
NET MWH (ON-LINE)	1,673,981	1,357,427	111,985	59,935	106,245	120,836	133,795	173,844	46,799	182,641	196,493	184,003	116,182	126,315	154,291	37,767	201,014
GAS ON-LINE (KCF)	17,262	9,904	221	759	1,587	0	1,817	17	4,378	0	0	1,717	0	0	6,985	1,841	0
PETCOKE ON-LINE (TONS)	437,099	326,250	26,603	7,389	24,154	28,929	35,520	48,300	11,684	45,761	49,879	47,972	32,720	30,503	41,601	10,120	53,522
COAL ON-LINE (TONS)	139,343	159,871	12,625	17,580	12,101	10,560	10,801	12,346	5,327	16,701	13,730	15,176	10,162	12,761	12,416	4,429	14,784
LIMESTONE	229,523	180,339	17,108	6,365	9,510	12,341	21,837	30,522	6,767	23,431	19,888	31,027	19,793	15,303	21,980	7,229	19,443
HEAT CONTENT - GAS	1,057	1,034	1,051	1,054	1,054	1,060	1,058	1,054	1,057	1,061	1,063	1,064	1,058	1,058	1,054	1,050	1,047
HEAT CONTENT - PETCOKE	14,107	13,949	14,133	13,893	14,240	14,321	14,257	14,182	14,042	13,932	14,273	14,215	14,044	14,263	14,002	13,973	13,950
HEAT CONTENT - COAL	12,827	11,907	13,044	12,874	12,901	12,985	13,012	12,943	13,092	13,152	13,064	13,077	13,125	12,674	12,328	12,380	12,156
HEAT RATE (O/L) (BTU/KWH, NET)	9,514	9,518	9,658	10,991	9,429	9,127	9,685	9,719	10,091	9,387	9,072	9,579	10,206	9,449	9,584	10,445	9,216
ATTEMPTED STARTS	18	31	5	9	4	2	1	0	8	0	0	1	0	2	1	2	1
STARTS	15	9	1	4	2	1	1	0	7	0	0	1	0	1	1	2	1
HOURS ONLINE	6,843	5,450	453.62	304.20	456.47	493.20	535.47	744.00	227.77	744.00	720.00	725.50	441.97	537.63	724.03	218.72	731.13
COMBUSTION HOURS	7,057	5,839	498.50	359.53	488.43	517.08	586.33	744.00	264.42	744.00	720.00	744.00	442.45	562.53	744.00	243.98	744.00
MBTUs GAS	71,578	100,073	8,544	3,603	6,746	6,196	19,001	18	17,221	0	0	6,163	0	5,943	7,363	5,637	4,037
MBTUs PETCOKE	12,359,656	9,148,226	753,749	206,871	692,649	834,198	1,018,439	1,369,951	336,196	1,275,106	1,423,873	1,363,830	919,015	872,260	1,164,979	287,891	1,493,919
MBTUs COAL	3,584,539	3,827,410	330,140	456,087	314,376	276,083	282,654	319,583	142,918	439,302	358,723	396,922	266,762	324,247	306,122	111,618	359,606
TOTAL MBTUs	16,016,637	13,076,471	1,092,467	666,562	1,013,771	1,116,476	1,320,094	1,689,552	496,334	1,714,408	1,782,596	1,767,066	1,185,777	1,202,591	1,478,716	405,359	1,857,668
% GAS	0.45%	0.77%	0.78%	0.54%	0.67%	0.55%	1.44%	0.00%	3.47%	0.00%	0.00%	0.35%	0.00%	0.49%	0.50%	1.39%	0.22%
% PETCOKE	77.17%	69.96%	69.00%	31.04%	68.32%	74.72%	77.15%	81.08%	67.74%	74.38%	79.88%	77.18%	77.50%	72.53%	78.78%	71.02%	80.42%
% COAL	22.38%	29.27%	30.22%	68.42%	31.01%	24.73%	21.41%	18.92%	28.79%	25.62%	20.12%	22.46%	22.50%	26.96%	20.70%	27.54%	19.36%
LOAD FACTOR (GROSS)	88.0%	90.0%	90.7%	77.9%	84.6%	88.9%	90.8%	85.3%	75.2%	89.0%	97.0%	90.4%	94.1%	84.0%	76.5%	63.6%	97.5%
CAPACITY FACTOR (GROSS)	68.7%	55.8%	55.3%	32.9%	51.9%	58.9%	72.4%	85.3%	23.8%	89.0%	97.0%	88.2%	55.9%	62.7%	74.5%	19.3%	95.8%
MWHs GAS	6,725	7,743	833	306	664	635	1,830	2	1,483	0	0	612	0	585	733	427	417
MWHs PETCOKE	1,281,223	928,734	76,958	18,391	71,426	89,554	102,734	140,959	30,313	135,841	156,951	141,927	87,099	89,889	121,402	22,847	161,708
MWHs COAL	369,948	385,473	33,707	40,546	32,419	29,638	28,513	32,883	12,886	46,800	39,541	41,306	25,282	33,414	31,901	8,858	38,925
12 mth rolling CAP FACTOR			32.0%	34.7%	39.1%	44.1%	49.4%	56.2%	56.5%	58.4%	62.7%	67.1%	66.2%	64.5%	66.1%	65.0%	68.7%
STACK EMISSIONS DATA - UNIT 2																	
SO2 Emissions, Tons	1,131.8	1,095.6	123.5	131.4	112.5	94.0	124.9	117.1	34.4	83.3	82.4	125.7	72.2	77.1	131.6	74.3	114.8
SO2 Emissions, lb/MBtu	0.14	0.17	0.23	0.39	0.22	0.17	0.19	0.14	0.14	0.10	0.09	0.14	0.12	0.13	0.18	0.37	0.12
NOx Emissions, Tons	525.5	492.6	30.5	46.7	24.8	38.1	51.9	48.5	27.4	51.8	66.4	43.7	37.3	34.1	29.3	28.4	68.6
NOx Emissions, lb/Mbtu	0.07	0.08	0.06	0.14	0.05	0.07	0.08	0.06	0.11	0.06	0.07	0.05	0.06	0.06	0.04	0.14	0.07
Particulate Matter, Tons	41.23	29.72	2.19	1.33	2.03	5.95	7.01	2.53	0.76	2.57	2.67	4.42	2.96	3.01	3.70	1.01	4.64
Particulate Matter, lb/Mbtu	0.005	0.005	0.004	0.004	0.004	0.011	0.011	0.003	0.003	0.003	0.003	0.005	0.005	0.005	0.005	0.005	0.005
CO, Tons	297.3	290.6	36.7	36.6	33.4	27.7	63.2	29.1	33.9	27.0	7.4	18.9	7.3	16.0	33.9	14.7	18.2
CO, lb/Mbtu	0.04	0.04	0.07	0.11	0.07	0.05	0.10	0.03	0.14	0.03	0.01	0.02	0.01	0.03	0.05	0.07	0.02
CO, lb/hr	84	100	147	204	137	107	216	78	256	73	21	51	33	57	91	121	49
VOC, Tons	11.92	11.63	1.47	1.46	1.34	1.11	2.53	1.16	1.36	1.08	0.29	0.76	0.29	0.64	1.40	0.60	0.70
VOC, lb/Mbtu	0.001	0.002	0.003	0.004	0.003	0.002	0.004	0.001	0.005	0.001	0.000	0.001	0.000	0.001	0.002	0.003	0.001
VOC, lb/hr	3.4	4.0	5.9	8.1	5.5	4.3	8.6	3.1	10.3	2.9	0.8	2.0	1.3	2.3	3.8	4.9	1.9
GADS DATA																	
Equivalent Availability Factor, EAF, %	72.8%	58.7%	Incompl Data	Incompl Data	Incompl Data	63.90%	78.70%	86.82%	29.65%	93.40%	99.76%	94.35%	57.22%	68.13%	77.24%	27.06%	97.58%

FILE: (0)JEADATA DRAKE	CALENDAR 2003	CALENDAR 2004	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03
WATER AND WASTEWATER FLOWS (UNITS 1, 2, AND 3)																	
Surface Water, Million Gallons	285,493	278,776	23,193	21,619	23,879	25,130	15,194	24,013	20,190	22,843	26,600	27,396	25,980	25,503	26,945	21,290	24,409
Ground Water, Million Gallons	193.6	215.7	15.7	17.7	18.3	18.0	15.4	17.8	15.6	14.8	14.0	17.9	17.2	18.2	14.2	15.3	15.2
Reuse Water, Million Gallons	276.8	254.5	14.7	2.4	13.9	19.4	22.1	19.8	22.9	30.3	36.7	1.1	0.0	15.1	52.4	50.7	6.4
CWTS Influent, Million Gallons	106.5	219.5	Not Available	Not Available	Not Available	Not Available	Not Available	Not Available	Not Available	Not Available	18.1	18.3	16.9	16.5	16.5	11.1	9.2
Perc Ponds to District II, Million Gal	46.3	48.2	Not Available	Not Available	Not Available	8.1	8.1	8.9	0.3	0.3	3.4	4.3	4.9	2.5	1.2	1.2	3.0
ASH PRODUCTION RATES																	
Total Bed Ash, Tons, Units 1 and 2	312,400	195,439															
Total Fly Ash, Tons, Units 1 and 2	179,700	153,623															
Unit 2 Portion of Bed Ash, Tons	153,236	96,515															
Unit 2 Portion of Fly Ash, Tons	88,145	75,865															
Byproduct Sales, Tons	0	38,312															
FUEL COSTS (nominal) $/mmBTU																	
GAS	6.23	6.66	4.82	4.81	5.49	6.14	7.80	7.15	6.06	6.55	6.61	5.82	5.75	5.41	5.41	5.13	6.89
NS PETCOKE	0.71	0.91	0.41	0.47	0.49	0.85	0.55	0.97	0.30	0.73	0.71	0.97	0.60	0.73	0.70	0.70	0.71
NS COAL	1.61	2.41	1.79	1.75	1.66	1.50	1.50	1.46	1.46	1.46	1.67	1.66	1.67	1.60	1.75	1.80	1.83
NS LIMESTONE $/ton			10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125

FILE: (0)JEADATA		DRAKE													
				Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
FUEL HEAT CONTENT															
NS-2 PETCOKE		HEAT CONTENT-BTU/LB		14,056	13,879	14,092	14,092	14,189	14,182	13,636	14,155	13,682	14,015	13,874	13,874
NS-2 COAL		HEAT CONTENT-BTU/LB		12,143	12,478	12,749	12,749	11,045	11,655	12,211	11,324	11,662	12,399	12,012	12,138
	NS-2	PETCOKE	%S	3.75	3.91	4.04	4.04	3.67	5.36	4.45	4.94	6.14	3.82	6.14	4.03
	NS-2	COAL	%S	2.93	3.23	2.98	2.98	2.77	2.64	2.71	0.62	3.01	2.68	2.26	2.66
	NS-2	PETCOKE	%ash	0.17	0.91	0.92	0.92	0.53	0.24	0.45	0.76	1.00	1.43	0.93	0.27
	NS-2	COAL	%ash	7.30	7.51	7.81	7.81	7.17	13.11	10.06	7.35	8.95	8.86	10.09	9.73
NS-2 OPER DATA		(GROSS CAP)	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5	297.5
		GROSS MWH GENERATED		197,874	54,281	71,595	0	141,806	87,405	167,506	209,458	196,519	158,750	470	173,687
		HOUSE LOAD MWH (ON-LINE)		14,360	4,381	5,991	0	10,113	7,305	9,609	14,151	14,333	10,831	16	10,834
		NET MWH (ON-LINE)		183,514	49,900	65,604	0	131,693	80,100	157,897	195,307	182,186	147,919	454	162,853
		GAS ON-LINE (KCF)		0	291	693	0	3,166	2,409	0	0	0	202	3,022	0
		PETCOKE ON-LINE (TONS)		27,092	12,565	16,129	0	32,971	7,829	39,467	53,336	52,289	39,700	305	44,731
		COAL ON-LINE (TONS)		39,350	5,357	7,981	0	11,653	25,811	15,391	14,239	15,843	10,386	322	13,270
		LIMESTONE		24,081	7,176	8,296	0	14,225	11,786	21,015	26,451	25,840	17,876	492	23,306
		HEAT CONTENT - GAS		1,055	1,050	1,049	1,050	1,056	1,049	1,054	1,054	1,052	1,052	1,053	1,048
		HEAT CONTENT - PETCOKE		14,056	13,879	14,092	14,092	14,189	14,182	13,636	14,155	13,682	14,015	13,874	13,874
		HEAT CONTENT - COAL		12,143	12,478	12,749	12,749	11,045	11,655	12,211	11,324	11,662	12,399	12,012	12,138
		HEAT RATE (O/L) (BTU/KWH, NET)		9,358	9,675	10,042	0	9,085	10,316	9,197	9,382	9,882	9,266	42,696	9,599
		ATTEMPTED STARTS		2	4	6	0	5	2	5	1	0	0	2	4
		STARTS		2	0	0	0	0	0	0	1	0	0	2	4
		HOURS ONLINE		714.02	227.15	308.03	0.00	508.83	383.08	604.00	725.83	720.00	623.62	6.13	628.93
		COMBUSTION HOURS		744.00	240.92	399.12	0.00	586.22	417.23	643.27	744.00	720.00	625.62	70.32	648.42
		MBTUs GAS		0	4,781	17,453	0	24,431	13,705	12,349	3,075	0	458	17,726	6,096
		MBTUs PETCOKE		761,612	356,304	460,809	0	940,229	223,116	1,087,371	1,511,364	1,430,880	1,113,215	12,376	1,250,950
		MBTUs COAL		955,650	136,580	206,275	0	258,681	604,522	379,744	322,809	369,503	257,642	11,315	324,690
		TOTAL MBTUs		1,717,262	497,665	684,659	0	1,223,612	841,498	1,479,545	1,837,247	1,800,383	1,371,323	41,417	1,581,860
		% GAS		0.00%	0.96%	2.55%	0.00%	2.00%	1.63%	0.83%	0.17%	0.00%	0.03%	42.80%	0.39%
		% PETCOKE		44.35%	71.60%	67.30%	0.00%	76.84%	26.51%	73.49%	82.26%	79.48%	81.18%	29.88%	79.08%
		% COAL		55.65%	27.44%	30.13%	0.00%	21.14%	71.84%	25.67%	17.57%	20.52%	18.79%	27.32%	20.53%
		LOAD FACTOR (GROSS)		93.2%	80.3%	78.1%	0.0%	93.7%	76.7%	93.2%	97.0%	91.7%	85.6%	25.8%	92.8%
		CAPACITY FACTOR (GROSS)		89.4%	26.2%	32.3%	0.0%	64.1%	40.8%	75.7%	94.6%	91.7%	71.7%	0.2%	78.5%
		MWHs GAS		0	412	1,472	0	2,463	1,190	1,250	312	0	46	0	598
		MWHs PETCOKE		81,227	32,143	40,703	-7,230	99,258	20,290	115,264	160,399	144,795	118,410	-4,975	128,450
		MWHs COAL		101,921	12,321	18,220	0	27,308	54,975	40,254	34,259	37,391	27,405	-1,921	33,340
		12 mth rolling CAP FACTOR		71.3%	67.7%	63.2%	0.0%	59.1%	54.5%	53.5%	56.7%	59.1%	58.9%	57.3%	55.8%
STACK EMISSIONS DATA - UNIT 2															
		SO2 Emissions, Tons		116.4	29.4	86.3	0.0	87.7	58.6	93.1	110.5	234.2	110.4	16.1	152.9
		SO2 Emissions, lb/MBtu		0.14	0.12	0.25	0.00	0.14	0.14	0.13	0.12	0.26	0.16	0.78	0.19
		NOx Emissions, Tons		69.8	26.5	29.5	0.0	46.6	29.9	55.0	68.6	55.7	41.5	4.0	65.5
		NOx Emissions, lb/Mbtu		0.08	0.11	0.09	0.00	0.08	0.07	0.07	0.07	0.06	0.06	0.19	0.08
		Particulate Matter, Tons		4.29	1.00	1.38	0.00	3.06	2.10	3.70	4.59	3.60	2.74	0.09	3.17
		Particulate Matter, lb/Mbtu		0.005	0.004	0.004	0.000	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004
		CO, Tons		61.6	10.5	41.1	0.0	30.7	39.1	46.5	17.3	7.8	6.4	8.4	21.2
		CO, lb/Mbtu		0.07	0.04	0.12	0.00	0.05	0.09	0.06	0.02	0.01	0.01	0.41	0.03
		CO, lb/hr		166	87	206	0	105	187	145	47	22	20	239	65
		VOC, Tons		2.46	0.42	1.64	0.00	1.23	1.57	1.86	0.69	0.31	0.26	0.34	0.85
		VOC, lb/Mbtu		0.003	0.002	0.005	0.000	0.002	0.004	0.003	0.001	0.000	0.000	0.016	0.001
		VOC, lb/hr		6.6	3.5	8.2	0.0	4.2	7.5	5.8	1.9	0.9	0.8	9.7	2.6
GADS DATA															
		Equivalent Availability Factor, EAF, %		94.73%	27.44%	38.55%	0.00%	68.12%	44.09%	79.41%	96.65%	94.53%	76.07%	0.43%	83.79%

FILE: (0)JEADATA DRAKE	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
WATER AND WASTEWATER FLOWS (UNITS 1, 2, AND 3)												
Surface Water, Million Gallons	25,430	22,265	26,308	20,589	24,764	25,420	26,964	26,827	25,938	24,180	12,747	17,344
Ground Water, Million Gallons	20.9	19.8	20.8	19.6	25.0	21.1	21.4	11.9	13.7	14.4	12.4	14.6
Reuse Water, Million Gallons	0.0	0.0	0.0	12.5	27.4	15.6	26.3	39.5	34.0	35.6	31.7	31.9
CWTS Influent, Million Gallons	12.6	12.8	14.3	15.0	19.0	19.6	14.6	18.7	22.5	30.9	20.0	19.3
Perc Ponds to District II, Million Gal	1.9	2.8	2.4	1.3	2.2	4.3	5.5	4.2	5.8	6.1	5.8	6.0
ASH PRODUCTION RATES												
Total Bed Ash, Tons, Units 1 and 2												
Total Fly Ash, Tons, Units 1 and 2												
Unit 2 Portion of Bed Ash, Tons												
Unit 2 Portion of Fly Ash, Tons												
Byproduct Sales, Tons												
FUEL COSTS (nominal) $/mmBTU												
GAS	6.81	6.15	6.13	6.49	7.10	7.08	6.76	6.24	5.79	7.15	6.75	7.51
NS PETCOKE	0.74	0.70	0.75	0.81	0.74	0.69	0.80	1.04	1.05	1.09	1.19	1.37
NS COAL	1.86	2.09	2.36	2.37	2.37	2.37	2.38	2.40	2.66	2.70	2.66	2.70
NS LIMESTONE $/ton	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125	10.125

APPENDIX D - Capital Cost Data

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Summary by WBS
Unit 2 and 50% of Common

UNIT 2	DOE Phase	Task	WBS	Actual Costs
	1B - Design			
		Project Management and Support	2.1.11	**3,164,454**
		Permitting	2.1.12	**2,390,444**
		Preliminary Design	2.1.13	**2,175,695**
		Engineering/Detailed Design	2.1.14	**23,371,293**
		Unit 2 - Subtotal 1B Design		**$31,101,886**
	2 - Construction and Start-up			
		Project Management and Support	2.2.21	**5,826,510**
		Environmental Monitoring	2.2.22	**29,871**
		Boiler Equip/AQCS	2.2.23	**119,043,822**
		Balance of Plant Equipment	2.2.24	**35,070,257**
		Turbine/Generator Refurbishment & Upgrade	2.2.26	**15,588,735**
		Unit 2 - Subtotal Construction and Start-up		**$175,559,195**

COMMON	DOE Phase	Task	WBS	50% of Actual Costs
	1B - Design			
		Engineering/Detailed Design	3.1.14	**2,932,126**
		Common - Subtotal Engineering/Detail Design		**$2,932,126**
	2 - Construction and Start-up			
		Project Management and Support	3.2.21	**20,294,905**
		Environmental Monitoring	3.2.22	**115,751**
		Boiler Equip/AQCS	3.2.23	**9,141,358**
		Balance of Plant Equipment	3.2.24	**29,254,424**
		Fuel Handling Equipment	3.2.25	**52,992,980**
		Common - Subtotal Construction and Start-up		**$111,799,417**

TOTAL CAPITAL COST (Unit 2 Plus 50% of Common) **$321,392,624**

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Breakdown by Work Package			
Unit 2			
Unit 2	**DOE Phase/Task**	**Work Package**	**Actual Costs**
	1B - Design		
	Project Management and Support	PLANT MANAGEMENT	37,331
		ENGINEERING	845
		PROJECT MANAGEMENT	1,403,425
		I S MATERIAL	12,651
		LEGAL SERVICES	1,129,981
		FINANCE COSTS	499,676
		TRAVEL & TRAINING	80,545
			3,164,454
	Permitting	PERMITTING	189,857
		PERMITTING	2,200,587
			2,390,444
	Preliminary Design	PLANT MANAGEMENT	65,106
		ENGINEERING	124,447
		PRELIMINARY TESTING	227,972
		PLANT SERV. MTL & LABOR	10,835
		PRELIM. DESIGN	1,747,335
			2,175,695
	Engineering / Detail Design	STRUCT. & IMPVT`S	1,131,857
		JEA PROVIDED SERVICES	19,150
		BOILER PLANT EQUIP.	11,493,344
		PLANT MANAGEMENT	8,724
		ENGINEERING	74,480
		TURBOGENERATOR UNITS	1,810,971
	Engineering / Detail Design	ACCESSORY ELECT. EQUIP.	8,832,767
			23,371,293
	Unit 2 - Subtotal 1B Design		**$31,101,886**
	2 - Construction and Startup		
	Project Management and Support	PLANT MANAGEMENT	26,465
		PROJECT MANAGEMENT	174,078
		JEA PROVIDED SERVICES	19,874
		INSURANCE	3,479,225
		CONST. MGMT	2,099,238
		TRAVEL & TRAINING	27,630
			5,826,510
	Environmental Monitoring	ENVIRON. MON.	29,871
			29,871
	Boiler Equipment / AQCS	PLANT SERV. MTL & LABOR	2,404
		CONCRETE STACK	1,330,358
		AQCS	12,928,202
		ASH HANDLING SYSTEM	2,928,044

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Breakdown by Work Package

Unit 2

Unit 2	DOE Phase/Task	Work Package	Actual Costs
		C F B BOILER SUPPLY	47,112,999
		CFB BOILER ERECTION	13,612,635
		JEA PROVIDED SERVICES	95,348
		CSA	5,392,566
		BOP EQUIPMENT (FW)	10,516,441
		CONSTRUCTION INDIRECTS	15,194,347
		START-UP SUPPORT	1,990,845
		ELECTRICAL	5,176,185
		AUTOMATION & CONTROLS	2,763,448
			119,043,822
	Balance of Plant Equipment	PLANT SERV. MTL & LABOR	3,341
		FIRE PROTECTION	929,251
		CONTROL ROOM MOD.	399,372
		PAINTING	183,114
		BOILER FEED PUMPS	367,677
		CONDENSATE POLISHERS	1,476,989
		CYCLE CHEM FEED EQUIP	169,780
		DEAERATOR	800,365
		FEEDWATER HEATERS	1,025,372
		WATER SAMPLE RACK	32,091
		BULK INSULATION	609,114
		JEA PROVIDED SERVICES	21,992
		BFP FLUID DRIVE	1,166,221
		CIVIL ZCC #5032	216
		CSA	680,520
		EQUIP. INSPECTION	34,750
		SYSTEM TESTING	114,951
		CONSTRUCTION INDIRECTS	132,846
		EQUIPMENT RENTAL	653,109
		OTHER PROC. & CONST.	51,141
		CIRC. WATER PUMPS	2,072,940
		CC WATER HEAT EXCHANGER	19,207
		CONDENSATE PUMPS	15,197
		VACUUM PUMPS	146,046
		CONDENSER	2,761,842
		CONDENSER CLEANING SYS.	122,346
		BW PUMP MOTORS	4,423
		FILL PUMP	4,428
		GEN. SERVICE PUMPS	271,188
		PIPING & VALVES	7,249,577
		TRAVELING SCREENS	540,223
		VOID GROUTING	39,031
		COND. BOOSTER PUMPS	97,818
		COND. BSTR PUMP FLUID DRIVE	11,860
		CCW SURGE TANK & PIPING	570,744
		CIRC WATER PUMP STRUCT.	15,491
		NEW PUMP MTR. PROC. & INST	772,433
		MED. VOLT. SWITCHGEAR	621,466

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Breakdown by Work Package			
Unit 2			
Unit 2	**DOE Phase/Task**	**Work Package**	**Actual Costs**
		5 kV BUS DUCT REFURB.	31,247
		CATHODIC PROTECTION	470,104
		DCS	2,129,791
		LOW VOLTAGE SWITCHGEAR	556,629
		480V MCC & PWR PANEL REPL	470,525
		NON-SEG PHASE BUS DUCT	310,272
		PROTECTION CIRCUIT SYSTEM	5,272
		TRANSFORMERS	116,507
		BULK INSTR. & CONTROLS	371,798
		BATTERIES	10,596
		UNIT 1&2 ELECT. SEPARATION	190,486
		CTRL RM PANEL & INSTR. MODS	523,376
		RACEWAY & CONDUIT	3,037,166
		POWER & CONTROL CABLE	1,675,222
		MISCELLANEOUS ELECTRICAL	982,794
			35,070,257
	Turbine Generator Refurb./Upgrade	PLANT SERV. MTL & LABOR	1,931
		JEA PROVIDED SERVICES	97,974
		CONSTRUCTION INDIRECTS	167,074
		TURBINE	15,321,756
			15,588,735
	Unit 2 - Subtotal Construction and Startup		**$175,559,195**
	TOTAL CAPITAL COST (Unit 2)		**$206,661,081**

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Breakdown by Work Package

50% of Common

COMMON	DOE Phase/Task	Work Package	50% of Actual Costs
	1B - Design		
	Engineering / Detail Design	ENGINEERING	191,377
		STRUCT. & IMPVT`S	172,113
		BOILER PLANT EQUIP.	1,905,449
		TURBOGENERATOR UNITS	82
	Engineering / Detail Design	ACCESSORY ELECT. EQUIP.	663,107
			2,932,127
	Common - Subtotal Engineering/Detail Design		**$2,932,127**
	2 - Construction and Startup		
	Project Management and Support	PLANT MANAGEMENT	5,937
		CONST. MGMT	10,635,958
		INSURANCE	1,749,871
		PROJECT MANAGEMENT	299,202
		START-UP SUPPORT	7,549,330
		TRAVEL & TRAINING	54,609
			20,294,905
	Environmental Monitoring	ENVIRON. MON.	114,131
		ENVIRON. MON.	1,620
			115,751
	Boiler Equipment / AQCS	PLANT SERV. MTL & LABOR	933
		LIMESTONE PREP SYSTEM	6,535,510
		CFB BOILER ERECTION	442,793
		CSA	224,690
		CONSTRUCTION INDIRECTS	760,917
		ELECTRICAL	215,675
		MED. VOLT. SWITCHGEAR	307,524
		LOW VOLTAGE SWITCHGEAR	179,706
		480V MCC & PWR PANEL REPL	243,841
		NON-SEG PHASE BUS DUCT	139,056
		TRANSFORMERS	90,716
			9,141,358
	Balance of Plant Equipment	PLANT SERV. MTL & LABOR	24,068
		SPARE PARTS	45,021
		FIRE PROTECTION	37,277
		PAINTING	685
		AIR DRYER	2,823,353
		ASH HANDLING CONVEYORS	2,884,203
		ASH STG. & UNLOADING	3,717,055

JEA NORTHSIDE REPOWERING PROJECT

Capital Cost Breakdown by Work Package

50% of Common

COMMON	DOE Phase/Task	Work Package	50% of Actual Costs
		REUSE WATER TRT`MT SYS.	474,439
		HYPOCHLORITE PIPING & TKS.	80,008
		CIVIL ZCC #5032	4,621,165
		CSA	1,038,510
		CONSTRUCTION INDIRECTS	8,751,601
		EQUIPMENT RENTAL	1,091,349
		OTHER PROC. & CONST.	2,660,811
		CIRC. WATER PUMPS	4,217
		FUEL OIL TRF. PUMPS	82,870
		PIPING & VALVES	835,876
		MED. VOLT. SWITCHGEAR	123,172
		LOW VOLTAGE SWITCHGEAR	7,055
		480V MCC & PWR PANEL REPL	36,593
		TRANSFORMERS	76,144
		RACEWAY & CONDUIT	-521,146
		POWER & CONTROL CABLE	266,058
		MISCELLANEOUS ELECTRICAL	94,045
			29,254,424
	Fuel Handling Equipment	LAND PURCHASES	322,365
		SHIP UNLOADER	4,573,600
		UNLOADING DOCK	6,785,740
		FIRE PROTECTION	582,371
		MHS CONVEYORS	9,397,439
		JEA PROVIDED SERVICES	29,949
		FUEL STORAGE DOMES	4,929,191
		STACKER/RECLAIMER	2,846,066
		CSA	126,387
		MHS TRANSFER TOWERS	6,445,708
		CONSTRUCTION INDIRECTS	14,676,079
		OTHER PROC. & CONST.	291,123
		PIPING & VALVES	2,947
		MED. VOLT. SWITCHGEAR	556,775
		DCS	32,220
		RACEWAY & CONDUIT	32,748
		POWER & CONTROL CABLE	1,215,400
		MISCELLANEOUS ELECTRICAL	146,878
			52,992,980
	Common - Subtotal Construction and Startup		**$111,799,417**
	TOTAL CAPITAL COST (50% of Common)		**$114,731,543**

JEA NORTHSIDE REPOWERING PROJECT

Phase 1 Capital Improvement Projects
Unit 2 CFB Boiler and AQCS

ITEM #	Project Description	Actual Costs
1	Limestone Feed System Modifications to Improve Flow and Stabilize Feed Rate	96,102
2	Upgrade Limestone Transport to Design Capacity	1,311,310
3	Improve Reliability and Drying Capability of Limestone Preparation System	146,817
4	Modifications to Improve Silo Flow	40,998
5	Distributed Control System Initial Evaluation	32,653
6	Revamp Boiler AQCS Instrumentation for Accurate and Reliable Process Control	394,436
7	Perform Modifications to Air Quality Control System Process and Equipment to Improve Reliability of Recycle Mix Process and Slurry Pumping System	522,927
8	INTREX Tube Support Modifications and Ash Flow Modeling	380,483
9	Wind box Refractory Replacement and Damper Modifications	152,419
10	Replace Rear wall Drag Chain Slide Gates	144,512
11	Upgrade Booster Blower Bearings & Install Startup Burner Instruments	126,083
12	Evaluate, Modify, and Repair the Stripper Cooler Inlet and Cyclone Inlet Expansion Joints	781,457
13	Refractory Upgrade and Spray Water Nozzle Modifications to Stripper Coolers	234,554
14	Upgrade Fly Ash Valves and Bed Ash Blower Sole Plates	186,420
15	Replace Failed Critical Pipe Supports	399,930
16	Install Boiler Maintenance Hoist and Platforms	386,765
17	Construction Punchlist, Turnover Documentation	359,290
	Total Phase 1 Capital Improvements Projects	**$5,697,156**

JEA NORTHSIDE REPOWERING PROJECT

Phase 2 Capital Improvement Projects
Unit 2 CFB Boiler and AQCS

Item #	Project Description	Actual Costs
1	AQCS Process Improvements	721,545
2	Improve Reliability of Bed Ash and Fly Ash Valves	111,702
3	Above Bed Burners, INTREX Tubes and Furnace Grid Nozzle Replacement; also, Perform Interim INTREX Modifications to Mitigate Tube Failures.	3,513,713
4	DCS, BOP Projects, Black Belt Study, and Turnover Documentation	1,195,852
5	Modify Limestone Silo Outlet and Limestone Metering Equipment to Improve Flow Control and Stability	725,220
6	Enhancement to Ash Transport and Ash Processing Systems	870,106
	Total Phase 2 Capital Improvements Projects	**$7,138,138**